December 14, 2023

Via email to: Chris.Crawford@martinmlp.com & First Class Mail

Chris Crawford
Environmental Specialist
Martin Operating Partnership L.P.
484 East 6th Street
Smackover, AR 71762

Re: Notice of Final Permitting Decision; Permit No. 1227-AOP-R8

Dear Mr. Crawford,

After considering the application and other applicable materials as required by APC&EC Rule 8.211 and Ark. Code Ann. § 8-4-101 *et seq*., this notice of final permitting decision is provided for:

Martin Operating Partnership L.P.
484 East 6th Street
Smackover, AR 71762

Permit Number: 1227-AOP-R8

Permitting Decision: approval with permit conditions as set forth in final Permit No. 1227-AOP-R8

Accessing the Permitting Decision:
https://www.adeq.state.ar.us/downloads/WebDatabases/PermitsOnline/Air/1227-AOP-R8.pdf.

Accessing the Statement of Basis:
https://www.adeq.state.ar.us/downloads/WebDatabases/PermitsOnline/Air/1227-AOP-R8-SOB.pdf.

Rule 26.903 of the Rules of the Arkansas Operating Air Permit Program do not require a public notice or public comment period for Administrative Amendments.

Sincerely,

Demetria Kimbrough

Demetria Kimbrough
Associate Director, Office of Air Quality, Division of Environmental Quality
5301 Northshore Drive, North Little Rock, AR 72118-5317

Enclosure: Certificate of Service

CERTIFICATE OF SERVICE

I, Natasha Oates, hereby certify that the final permit decision notice has been mailed by first class mail to Martin Operating Partnership L.P., 484 East 6th Street, Smackover, AR, 71762, on this 14th day of December, 2023.

Natasha Oates

Natasha Oates, AA, Office of Air Quality

DIVISION OF ENVIRONMENTAL QUALITY

OPERATING AIR PERMIT

PERMIT NUMBER: 1227-AOP-R8

IS ISSUED TO:
Martin Operating Partnership L.P.
484 East 6th Street
Smackover, AR 71762
Union County
AFIN: 70-00039

PURSUANT TO THE RULES OF THE ARKANSAS OPERATING AIR PERMIT PROGRAM, RULE 26: THIS PERMIT AUTHORIZES THE ABOVE REFERENCED PERMITTEE TO INSTALL, OPERATE, AND MAINTAIN THE EQUIPMENT AND EMISSION UNITS DESCRIBED IN THE PERMIT APPLICATION AND ON THE FOLLOWING PAGES. THIS PERMIT IS VALID BETWEEN:

December 14, 2023 AND December 13, 2028

THE PERMITTEE IS SUBJECT TO ALL LIMITS AND CONDITIONS CONTAINED HEREIN.

Signed:

Demetria Kimbrough
Associate Director, Office of Air Quality
Division of Environmental Quality

December 14, 2023
Date

Table of Contents

List of Acronyms and Abbreviations

Ark. Code Ann.	Arkansas Code Annotated
AFIN	Arkansas DEQ Facility Identification Number
C.F.R.	Code of Federal Regulations
CO	Carbon Monoxide
COMS	Continuous Opacity Monitoring System
HAP	Hazardous Air Pollutant
Hp	Horsepower
lb/hr	Pound Per Hour
NESHAP	National Emission Standards (for) Hazardous Air Pollutants
MVAC	Motor Vehicle Air Conditioner
No.	Number
NO_x	Nitrogen Oxide
NSPS	New Source Performance Standards
PM	Particulate Matter
PM_{10}	Particulate Matter Equal To Or Smaller Than Ten Microns
$PM_{2.5}$	Particulate Matter Equal To Or Smaller Than 2.5 Microns
SNAP	Significant New Alternatives Program (SNAP)
SO_2	Sulfur Dioxide
SSM	Startup, Shutdown, and Malfunction Plan
Tpy	Tons Per Year
UTM	Universal Transverse Mercator
VOC	Volatile Organic Compound

SECTION I: FACILITY INFORMATION

PERMITTEE:	Martin Operating Partnership L.P.
AFIN:	70-00039
PERMIT NUMBER:	1227-AOP-R8
FACILITY ADDRESS:	484 East 6th Street Smackover, AR 71762
MAILING ADDRESS:	484 East 6th Street Smackover, AR 71762
COUNTY:	Union County
CONTACT NAME:	Chris Crawford
CONTACT POSITION:	Environmental Specialist
TELEPHONE NUMBER:	(870) 864-7819
REVIEWING ENGINEER:	Alexander Sudibjo
UTM North South (Y):	Zone 15: 3691692.87 m
UTM East West (X):	Zone 15: 526334.7 m

SECTION II: INTRODUCTION

Summary of Permit Activity

Martin Operating Partnership L.P. (MOP) operates an oil refinery at 484 East Sixth Street, in Smackover, Union County, Arkansas, 71762. With this renewal, the facility is making the following changes:

- Move Tank 113 from SN-27i to SN-27e since it is now in crude oil service.
- Remove Tanks 348, 349, 351, 352, 353, 247, 248, and 299 from SN-27i as they were never installed or were removed from service.
- Remove Tank 122 from SN-27l since it was never installed.
- Remove Tank 104 from SN-28 since it will be removed from service.
- Revise emissions from Tank 206 (SN-27f), Tank 210 (SN-27h), and the Sour Water Stripper Surge Tank (IA-3) using the TankESP emissions calculation software.
- Update annual throughput and maximum pump rate for the Miller's Bluff Storage Tanks (SN-29) to be only based on truck unloading as barge unloading no longer takes place at Miller's Bluff.
- Update wastewater emissions based on the most recent benzene sampling results.
- Update fugitive emissions based on the most recent fugitive component count.
- Update haul road emissions based on a revised material density according to the product SDS and revised annual throughput due to barge unloading no longer taking place at Miller's Bluff.
- Remove the 330-gal Fuel Additive Tanks A and B and 8,812-gal Diesel Tank 116 from the A-3 insignificant activities list. These tanks are out of service.
- Remove the 50 HP Low Pressure Boiler from the A-1 insignificant activities list. The boiler was never installed.
- Update emissions for the Miller's Bluff Crude Oil Truck Loading (IA-13) due to revised vapor pressure of liquid loaded and revised annual loading throughput.

The facility's permitted annual emissions are increasing by 0.6 tpy PM, 0.1 tpy PM_{10}, 1.2 tpy VOC, 0.1 tpy total HAPs, 0.04 tpy acetone, and 1.05 tpy H_2S. The facility's permitted annual emissions are decreasing by 0.02 tpy benzene.

Process Description

Martin Operating Partnership L.P. (MOP) is a refinery which processes produced naphthenic crude oil into naphtha, distillate, lube oils, and asphalt. MOP also operates an adjoining packaging facility. Trucks deliver locally produced and Grade A crude oil daily to the tanks at Sandyland (SN-28). Crude oil from Sandyland storage tanks (SN-28) is pumped to the onsite Crude Oil Storage Tanks 109 and 113 (SN-27e) and is preheated with heat exchangers. The crude passes through an electrostatic desalting unit which separates the saltwater from the crude. From the desalters, the crude is heated through a series of exchangers and then through the Crude Charge Heater (SN-01). Finally, the crude is sent to the atmospheric distillation tower where the oil is separated into naphtha, distillate, No. 2, No. 3 and No. 4 lube oils.

Naphtha and other non-condensable gases flow overhead from the atmospheric tower. The naphtha is cooled in a condenser and then flows to an accumulator from which a portion of the naphtha liquid is pumped back to the tower as reflux. Excess naphtha is drawn off of the accumulator and pumped to product storage for sales. Distillate and lube oils No. 2, 3, and 4 are drawn off of the side of the tower, routed through strippers to remove non-condensable gases, and then pumped through a series of exchangers and on to storage tanks (SN-27f and SN-27l) where distillate is loaded at SN-14. The naphtha loading rack is equipped with a vapor recovery system and all emissions are captured and routed back to the naphtha storage tanks.

The bottom stream (residue) off the atmospheric tower is pumped through the Vacuum Tower Charge Heater (SN-02) before being charged to the vacuum distillation column. The residue is separated in the vacuum tower to produce the heavier grades of lube oil (No. 7, 9, 10, and 11) and pumped through a series of exchangers and then to storage for product sales. The vacuum tower bottoms are asphalt flux which is pumped through heat exchangers to storage tanks (SN-27c and SN-27d) and then circulated through the Asphalt Heater (SN-03) to maintain tank temperature. The asphalt product is loaded into trucks and tank cars at one of the asphalt loading facilities (SN-15, SN-16, and SN-32).

The lube oils produced by both atmospheric and vacuum distillation are further processed in a set of exchangers and then are passed to the hydrotreaters. The oils are heated with heat exchangers and the Hydrotreater Charge Heater (SN-30), before being pumped into the top of each reactor. The hot lube oils combine with hydrogen at the top of each reactor before passing through a catalyst bed. Sulfur in the oil reacts with the hydrogen to form hydrogen sulfide gas. The hydrogen sulfide gas also saturates the aromatic compounds in the oil, removes heavy metals, and converts some nitrogen to ammonia.

The effluent from HD5 reactor #2 flows to a high-pressure separator where the excess hydrogen, hydrogen sulfide, and ammonia gases flash off. From the high-pressure separator, the oil flows to a low-pressure separator where additional light ends flash off. The oil then flows to a lube stripper where the remaining hydrogen sulfide is removed by stream stripping. The Stripper Charge Heater No. 1 (SN-12) supplies heat to the lube oil stripper. From the lube stripper, the oil flows to a vacuum flash tower where any entrained water is vacuum stripped from the product. The bottoms from the vacuum stripper tower are routed to finished lube storage tanks (SN-27h and SN-27i) for blending and sales. MOP stores additives in several storage tanks (SN-27a) and adds additives to the lube oil within the refinery, as needed, for quality control purposes. The finished lube products are loaded at lube oil loading racks (SN-17, SN-18, SN-21, and SN-33) and pumped to the Packaging Plant.

The waste gas from the high-pressure separator is routed to a gas/oil/water (GOW) separator. Gas from the GOW is then treated through two-stages of caustic scrubbing and two recycle reactors. Clean hydrogen gas from the recycle reactors is filtered and sent back to the hydrotreater reactors. The waste gas from the low-pressure separator combines with gas from the lube stripper. The combined gas stream is mixed with caustic through inline mixers and treated in two NaHS reactors. The clean mixed gas is filtered again then sent to the fuel gas mix drum and can then be delivered to various process heaters.

The primary hydrogen is supplied to the hydrotreaters by a steam/methane reformer (SN-08). The reformer's natural gas is compressed, heated in a preheat exchanger, and combined with steam. The mixture is charged to the hydrogen reformer where it passes over a catalyst and reacts with steam to produce hydrogen and carbon oxides. The gases leaving the reactor are routed to a shift converter which contains an iron-chromium catalyst. Most of the carbon monoxide (CO) in the gas is converted to carbon dioxide (CO_2) and hydrogen (H_2). The CO_2 and H_2 gas then flow to a pressure swing absorption (PSA) system where the CO_2 and other impurities are removed.

Steam is produced in a natural gas fired boiler (SN-26) at the facility. Steam is also produced by the reformer to be used at the reformer with excess steam routed to processes at the facility. The facility has one process flare (SN-40) for controlling excess hydrogen and process gas as well as controlling emergency releases from the crude unit and the hydrogen reformer units. The facility also has three fire pump emergency engines (SN-41, SN-42, and SN-43) and a diesel emergency generator (SN-48).

Sour water is produced from various processes at the facility and routed to a Sour Water Surge Tank for storing process surges of sour water being routed to the sour water stream stripper for treatment. The sour water stripper and associated tanks, with the exception of the sour water surge tank, vent into a closed system that delivers to the sodium hydrosulfide (NaHS) unit for byproduct recovery. The effluent water from the sour water stripper is reused in the process.

The wastewater produced from the various processes at the facility is collected and routed to the wastewater surge tanks before being routed to the facility's wastewater treatment system (SN-24). The wastewater is first routed to the covered API oil-water separators to remove any oil before being routed to the dissolved air flotation (DAF) tank and thence to four (4) DAF effluent tanks. Reclaimed oil from the wastewater is stored in several storage tanks (SN-27k). From the DAF effluent tanks, the wastewater is routed through three (3) new moving bed biofilm reactors (MBBR) before being routed to a secondary DAF unit for final biological treatment. The treated wastewater is then passed through a dissolved oxygen tower before being discharged to Smackover Creek via Outfall 001.

Rules and Regulations

The following table contains the rules and regulations applicable to this permit.

Rules and Regulations
Arkansas Air Pollution Control Code, Rule 18, effective March 14, 2016
Rules of the Arkansas Plan of Implementation for Air Pollution Control, Rule 19, effective May 6, 2022
Rules of the Arkansas Operating Air Permit Program, Rule 26, effective March 14, 2016
40 C.F.R. § 60 Subpart J – *Standards of Performance for Petroleum Refineries*
40 C.F.R. § 60 Subpart Ja – Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007
40 C.F.R. § 60 Subpart UU – *Standards of Performance for Asphalt Processing and Asphalt Roofing Manufacture*
40 C.F.R. § 60 Subpart QQQ – *Standards of Performance for VOC Emissions From Petroleum Refinery Wastewater Systems*
40 C.F.R. § 60 Subpart IIII – *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines*
40 C.F.R. § 61 Subpart FF – *National Emission Standards for Hazardous Air Pollutants, Benzene Waste Operations*
40 C.F.R. § 63 Subpart ZZZZ – *National Emission Standard for Stationary Reciprocating Internal Combustion Engines*
40 C.F.R. § 63 Subpart CCCCCC – *National Emission Standards for Hazardous Air Pollutants for Source Category: Gasoline Dispensing Facilities*

Subpart FF applies because MOP is a petroleum refinery. The boiler SN-26 was manufactured in 1971 and is therefore not subject to the requirements of NSPS Subpart Dc. The reformer SN-08 burns pipeline quality gas so it is not subject to 40 C.F.R. § 60 Subpart J – *Standards of Performance for Petroleum Refineries*.

Although the lube oil tanks #026p, #027p, #028p, #029p (1,182 barrel), #031p, #032p, #229, #230, #231, #232, #233, #332, #333, #334, #335, #336, #337, #338, #339, #340, #P041, #P042, #P043, #P044, #P045, #P046, #P047, #P048, #P049, #P050, #P051, #P052, #P060, #P061, #P062 and #P063 are greater than 75 cubic meters (19,813 gallons), the vapor pressure of the lube oil (<0.007 kPa) is below the NSPS Subpart Kb threshold of 3.5 kPa, therefore, the lube oil tanks are not subject to any other requirements of Subpart Kb.

40 C.F.R. § 60 Subpart GGG – *Standards Performance for Equipment Leaks of VOC in Petroleum Refineries*. This regulation applies to certain compressors and other equipment in VOC service installed after January 4, 1983. The permittee consultant's letter dated April 25, 2007 states that all compressors installed after the effective date are in hydrogen service and are not in VOC service. Therefore, no compressors at this facility are subject to Subpart GGG.

Emission Summary

The following table is a summary of emissions from the facility. This table, in itself, is not an enforceable condition of the permit.

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
Total Allowable Emissions		PM	21.0	26.0
		PM_{10}	7.5	12.1
		$PM_{2.5}$	See Note*	
		SO_2	84.1	7.4
		VOC	1696.7	186.4
		CO	790.6	92.9
		NO_X	225.3	74.5
HAPs		Benzene** Total HAPs	3.22 16.43	3.42 16.73
Air Contaminants ***		Acetone H_2S	0.03 1.17	0.12 3.25
01	Crude Charge Heater 32 MMBtu/hr	PM PM_{10} SO_2 VOC CO NO_x Benzene Total HAPs	0.4 0.4 1.1 0.3 3.4 4.0 0.01 0.08	1.4 1.4 1.8 1.0 14.6 17.4 0.01 0.33
02	Vacuum Tower Charge Heater 12.6 MMBtu/hr	PM PM_{10} SO_2 VOC CO NO_x Benzene Total HAPs	0.2 0.2 0.5 0.1 1.4 1.6 0.01 0.03	0.6 0.6 0.7 0.4 5.8 6.9 0.01 0.13
03	Asphalt Charge Heater	PM PM_{10} SO_2 VOC	0.1 0.1 0.3 0.1	0.4 0.4 0.5 0.3

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
		CO NO_x Benzene Total HAPs	0.9 1.0 0.01 0.02	3.7 4.4 0.01 0.09
07	Lube Charge Pre-Heater	Removed from service		
08	Hydrogen Reformer No.1 30 MMBtu/hr	PM PM_{10} SO_2 VOC CO NO_x Benzene Total HAPs	0.3 0.3 0.1 0.2 2.5 1.5 0.01 0.06	1.0 1.0 0.1 0.8 10.9 6.5 0.01 0.25
12	Stripper Charge Heater No. 1 14 MMBtu/hr	PM PM_{10} SO_2 VOC CO NO_x Benzene Total HAPs	0.2 0.2 0.5 0.1 1.5 1.8 0.01 0.04	0.6 0.6 0.8 0.5 6.5 7.7 0.01 0.15
14	Distillate/Naphtha Loading Rack	VOC Benzene Total HAPs	0.5 0.01 0.01	0.3 0.01 0.01
15	Asphalt/Black Oil Truck Loading Rack No.1	VOC Benzene Total HAPs	1.1 0.34 0.94	1.2[1] 0.38[1] 1.03[1]
16	Asphalt/Black Oil Truck Loading Rack No.2	VOC Benzene Total HAPs	1.1 0.34 0.94	
17	Lube Oil Truck Loading Rack	VOC Benzene Total HAPs	0.1 0.01 0.01	0.4[2] 0.01[2] 0.02[2]
18	Lube Oil Truck Loading Rack	VOC Benzene Total HAPs	0.1 0.01 0.01	
21	Lube Oil Rail Car Loading Rack	VOC Benzene Total HAPs	0.2 0.01 0.01	

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
23	Fugitive Emissions	VOC Benzene Total HAPs	25.7 0.12 1.62	112.5 0.49 7.07
24	Wastewater Emissions	VOC Acetone Benzene H_2S Total HAPs	2.4 0.03 0.03 0.74 0.16	10.6 0.12 0.11 3.24 1.14
25	Cogeneration Unit	Removed from service		
26	Boiler #4 94 MMBtu/hr	PM PM_{10} SO_2 VOC CO NO_x Benzene Total HAPs	0.8 0.8 0.1 0.6 7.8 3.7 0.01 0.18	3.1 3.1 0.3 2.3 34.1 16.2 0.01 0.77
27a	Refinery Additive Storage Tanks	VOC	0.1	0.1
27b	Packaging Plant Additive Storage Tanks	VOC	0.1	0.1
27c	Asphalt Storage Tanks	VOC Benzene Total HAPs	0.3 0.09 0.29	0.2 0.06 0.19
27d	Black Oil Storage Tanks	VOC Benzene Total HAPs	0.9 0.30 0.88	0.3 0.10 0.27
27e	Crude Oil Storage Tanks	VOC Benzene Total HAPs	5.6 0.33 0.61	7.9 0.47 0.87
27f	Untreated Distillate Storage Tanks	VOC Benzene Total HAPs	0.8 0.01 0.02	0.6 0.01 0.01
27g	Gasoline Storage Tank	VOC Benzene Total HAPs	38.7 0.31 7.52	1.0 0.01 0.19
27h	Untreated Lube Oil Storage Tanks	VOC Benzene Total HAPs	0.3 0.01 0.02	0.3 0.01 0.02

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
27i	Refinery Treated Lube Oil Storage Tanks	VOC Benzene Total HAPs	0.4 0.01 0.02	0.7 0.01 0.03
27j	Packaging Plant Lube Oil Storage Tanks	VOC Benzene Total HAPs	0.3 0.01 0.01	0.3 0.01 0.01
27k	Reclaim Oil Storage Tanks	VOC Benzene Total HAPs	0.3 0.01 0.01	0.2 0.01 0.01
27l	Treated Distillate Storage Tanks	VOC Benzene Total HAPs	0.6 0.01 0.01	0.6 0.01 0.01
28	Sandyland Storage Tanks	VOC Benzene Total HAPs	12.1 0.72 1.33	17.8 1.06 1.96
29	Miller's Storage Tanks (2 Total Crude Oil Tanks) Tanks #114 and #115	VOC Benzene Total HAPs	4.1 0.01 0.21	4.4 0.01 0.23
30	Hydrotreater Charge Heater	PM PM_{10} SO_2 VOC CO NO_x Benzene Total HAPs	0.1 0.1 0.1 0.1 0.6 0.4 0.01 0.02	0.3 0.3 0.1 0.2 2.6 1.6 0.01 0.06
32	Asphalt/Black Oil Tank Car Loading Rack	VOC Benzene Total HAPs	1.1 0.34 1.11	1.2 0.38 1.24
33	Lube Oil and Distillate Railcar Loading and Additive Railcar Unloading	VOC Benzene Total HAPs	1.0 0.01 0.02	0.8 0.01 0.02
34	Packaging Plant Lube Oil Loading/Unloading Docks	VOC Benzene Total HAPs	0.2 0.01 0.02	0.3 0.01 0.02
36	Lube Charge Heater No. 1	Removed from service		
37	Hydrogen Reformer No. 2	Removed from service		

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
38	Lube Charge Heater No. 2	Removed from service		
39	Stripper Charge Heater No. 2	Removed from service		
40	Flare	PM PM_{10} SO_2 VOC CO NOx Benzene H_2S Total HAPs	0.1 0.1 79.5 1592.2 747.9 164.1 0.02 0.43 0.08	0.1 0.1 2.5 17.2 8.5 1.9 0.07 0.01 0.34
41	Fire Pump Engine No.1	PM PM_{10} SO_2 VOC CO NOx Benzene Total HAPs	0.1 0.1 0.7 0.9 1.1 1.6 0.01 0.01	0.1 0.1 0.2 0.3 0.3 0.4 0.01 0.01
42	Fire Pump Engine No. 2	PM PM_{10} SO_2 VOC CO NOx Benzene Total HAPs	0.4 0.4 0.4 0.5 1.2 5.3 0.01 0.01	0.1 0.1 0.1 0.2 0.3 1.4 0.01 0.01
43	Fire Pump Engine No. 3	PM PM_{10} SO_2 VOC CO NOx Benzene Total HAPs	0.1 0.1 0.7 0.9 1.1 1.6 0.01 0.01	0.1 0.1 0.2 0.3 0.3 0.4 0.01 0.01
44	Packaging Plant Railcar Loading and Unloading Rack	Removed from service		

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
45	Packaging Plant Truck Loading and Unloading Rack	VOC Benzene Total HAPs	0.1 0.01 0.01	0.2 0.01 0.01
46	Haul Roads	PM PM_{10}	16.9 3.4	17.8 3.9
47	Surplus Loading/Unloading Rack	VOC Benzene Total HAPs	0.1 0.02 0.05	0.2 0.06 0.20
48	Diesel Emergency Generator	PM PM_{10} SO_2 VOC CO NO_x Benzene Total HAPs	1.3 1.3 0.1 2.4 21.2 38.7 0.02 0.05	0.4 0.4 0.1 0.6 5.3 9.7 0.01 0.02

*$PM_{2.5}$ limits are source specific, if required. Not all sources have $PM_{2.5}$ limits.
**HAPs included in the VOC totals. Other HAPs are not included in any other totals unless specifically stated.
***Air Contaminants such as ammonia, acetone, and certain halogenated solvents are not VOCs or HAPs.
[1]Combined total for SN-15 and SN-16.
[2]Combined total for SN-17, SN-18, and SN-21.

SECTION III: PERMIT HISTORY

1227-A Issued on December 9, 1991, this was the first operating permit for CORC. This permit included the inclusion of a recently installed naphtha storage tank.

1227-AR-1 This modification, issued on July 14, 1992, covered the installation of a lube-oil stripper/reboiler/heater at the facility.

1227-AR-2 Issued on November 20, 1992, this permit allowed the installation of a replacement boiler. The installation of the replacement boiler classified the facility as a major source subject to Title V permitting since NO_x emissions exceeded 100 tons per year.

1227-AR-3 This permit was issued on August 5, 1997 due to an emissions inventory that discovered that the facility did not have actual emissions greater than the major source threshold. Therefore, Cross Oil Refining and Marketing, Inc. was removed from major source status. Additionally, a cogeneration unit and the #4 boiler were added as sources at the facility.

1227-AR-4 This modification was issued on June 29, 2000 and covers the relocation of a 94.3 MMBTU/hr natural gas fired boiler to the facility. Several boilers at the plant had reached the end of their useful life. This new boiler incorporates a low NO_x burner and flue gas recirculation to minimize emissions. Additionally, it was planned that a duct burner would work in conjunction with a cogeneration unit, but the duct burner was never installed and is being removed from the permit and the cogeneration unit calculations adjusted accordingly. In order for CORC to install the duct burner, a new application must be submitted. Also, the existing #3 Boiler (SN-06) has been retired from operation and so the emissions from this source have been removed.

1227-AR-5 This permit was issued on April 29, 2002 and addressed a proposal to make the following changes to some storage tanks:

- Two tanks which stored lube oil product were destroyed in a fire in 1999 and have not yet been replaced. The refinery plans to move two existing identical tanks to replace these tanks. These tanks will be designated as #328 and #329. Both tanks have a capacity of 1,000 barrels each (42,000 gallons) and will be subject to the record keeping provisions of 40 CFR Part 60, Subpart Kb, since they will store organic liquids;
- Two tanks (#330 and #331), which will store lube oil product, are planned for installation. The tanks have a capacity of 10,000 barrels each (420,000 gallons) and will be subject to record keeping provisions of 40 CFR 60, Subpart Kb, since they will store organic liquids;
- Two tanks (#332 and #333), which will store lube oil product, are planned for installation. The tanks have a capacity of 500 barrels each (21,000 gallon) and will be subject to the record keeping provisions of 40 CFR 60, Subpart Kb, since they will store organic liquids; and

- One existing tank (#284), which is currently permitted to store lube oil, will be removed from service.

The total emissions VOC from the six tanks amounted to less than 0.02 tons annually.

1227-AR-6 This permit was issued on August 2, 2002 and addressed the following modifications to the facility:

- Tank #329 was recently permitted as a lube oil storage tank. This tank will be equipped with an internal floating roof and will store naphtha. The tank will be subject to the provisions of NSPS Subpart Kb. A floating roof meeting the requirements of 40 CFR 60 60.112b (a) (1) will be installed;
- The existing naphtha tank #206 will be converted to a lube oil storage tank. It was constructed in 1980 and will not be modified with this project. Therefore, the tank will not be subject to NSPS Subpart Kb after the change of service;
- Tanks #291 and #292 will be changing service from diesel to lube oil storage. The tanks were constructed in 1980. Therefore, the tanks will not be subject to NSPS Subpart Kb after the change of service; and
- Tank #113 is currently permitted as a crude oil storage tank subject to NSPS Subpart Ka. It will be changing service to store Cross Oil's B Series lube oil (a mixture of lube oil and diesel). The tank was constructed in 1980. Therefore, the tank will not be subject to NSPS Subpart Kb (or NSPS Subpart Ka due to the low vapor pressure of the lube oil) after the change of service.

The above changes in tank service resulted in a decrease in VOC emissions of 2.9 tons per year. Without considering the reduction in emissions due to the change in service of the tanks, the total increase associated with this project is 0.74 tons VOC per year.

1227-AR-7 This permit was issued on October 29, 2002 and addressed the following modifications to the permit:

- Addition of six tanks (001 through 006), which will store lube oil product, are planned for installation. The tanks have a capacity of 15,250 gallons each and will be subject to the record keeping provisions of 40 CFR 60, Subpart Kb, since they will store organic liquids; and
- Addition of three tanks (007 through 009), which will store lube oil product, are planned for installation. The tanks have a capacity of 2,000 gallons each and will not be subject to the record keeping provisions of 40 CFR 60, Subpart K.

The above changes resulted in an increase of VOC emissions of 0.2 tons per year.

1227-AR-8 This permit was issued on May 30, 2003 and allowed the facility to modify its existing permitted emission rates based upon emission factors, physical property data, facility operating conditions, and revised emissions modeling. In addition, the facility proposed to include hazardous air pollutant (HAP) emissions, which were not included in permit 1227-AR-7, to permit emissions from offsite storage tanks, and to correct opacity limits. No production increases were proposed. The proposed changes resulted in an increase of 0.7 tons per year of SO_2 emissions, 31.0 tons per year of CO emissions, and 15.8 tons per year of HAP emissions.

1227-AR-9 This permit was issued on April 19, 2004, and it allowed the facility to install two new 3,500 gallon lube oil storage tanks (#010p and #011p). The proposed change resulted in no production and negligible annual emissions increases.

1227-AR-10 This permit was issued September 28, 2004. CORC's proposal included the installation of one new 21,000 gallon reclaimed oil storage tank, one new 42,000 gallon reclaimed oil storage tank, and six new 16,800 gallon lube oil storage tanks. In addition to installing the new storage tanks, Cross Oil requested to remove #500, re-designate #332 as #500, and to re-designate #312 and #333 as #512 and #513, respectively.

1227-AR-11 This permit was issued April 11, 2005. The permit revision contained the following changes: converted two tanks containing asphalt to lube oil (Tank #223 and #224); added a new lube oil tank (Tank #331); converted a tank currently containing lube oil to naphtha (Tank #312); corrected the current tank numbering by shifting Tank #012P though #017P each up one number, resulting in Tank #013P through #018P; added two new lube oil tanks (Tanks #012P and #019P of SN-27); added a seasonal 50 horsepower (0.125 MMBTU/hr) low pressure boiler as an insignificant activity; added a pre-heat lube charge heater, with a design rating of 6.0 MMBTU/hr (SN-30) with low NO_x burners; added 7 heat exchangers (no source number) to the process in order to increase efficiency and reduce reliance on the crude heaters; and removed the crude oil throughput limit. Total annual emission increases were 0.2 ton/yr PM/PM_{10}, 0.1 ton/yr SO_2, 0.4 ton/yr VOC, 1.3 ton/yr NO_x, and 2.2 ton/yr CO.

1227-AR-12 This permit was issued on September 23, 2005. The facility modified their permit in order to increase the annual asphalt throughput at the Blow Still Incinerator Waste Heat Boiler (SN-04) and to remove the testing requirements for SO_2 at the Cogeneration Unit (SN-25), which is a natural gas source. Annual particulate emissions increased by 14.6 tons/year as a result of the asphalt throughput.

1227-AR-13 This permit was issued October 24, 2006. The permitting action was necessary to: install five 700 barrel (29,400 gallons) lube oil storage tanks at SN-27 (Tanks #020p, #022p, #023p, #024p, and #025p), install one 500 barrel (21,000 gallons) lube oil storage tank at SN-27 (Tank #021p), install one 5,000 barrel (210,000 gallons) lube oil storage tank at SN-27 (Tank #030p), and remove the 1000 barrel (42,000 gallon) reclaimed oil storage tank and replace it with a 400 barrel (16,800 gallon) reclaimed oil storage tank at SN-27 (Tank #503). In addition, the permitted HAP lb/hr emission rate limits were corrected for the Diesel/Naphtha/Kerosene Loading Rack (SN-14), and various typographical errors were corrected. The typographical errors included adding SN-23's VOC emissions back to Specific Condition #1; adding naphthalene to the Total Allowable Emissions Table; and correcting the VOC, NO_x, and toluene total emission rates in the Total Allowable Emissions Table. The total permitted annual emission rate increases included: 0.1 tpy NO_x, 0.01 tpy cumene, 0.01 tpy phenol, and 0.01 tpy toluene.

1227-AR-14 This permit was issued August 27, 2007. The permit revision contained the following changes:

- Installation of Six (6) lube oil storage tanks at SN-27 with the following storage capacities: Tanks #026p (1,182 barrel), #027p (1,049 barrel), #028p (862 barrel), #029p (1,182 barrel), #031p (1,182 barrel), #032p (1,049 barrel);
- Installation of one 1,000 barrel distillate oil storage tank (Tank #319) at SN-27;
- Removing of the 1000 barrel reclaimed oil storage tank and replacing it with a 400 barrel reclaimed oil storage tank at SN-27 – Tank #504;
- Installation of four (4) 280 barrel reclaimed oil storage tanks at SN-27; Tanks #514, #515, #516, and #517;
- Add an asphalt tank car loading rack;
- Add a distillate lube oil loading rack; and
- Revise insignificant activity list in the existing permit.

Cross Oil also submitted a De Minimis application to perform the necessary piping modifications to allow for pipeline quality natural gas to be fired at Blow Still Incinerator Waste Heat Boiler (SN-04), Lube Stripper Reboiler (SN-12), and Lube Charge Heater (SN-30); to include use of mixed gas at the Crude Charge Heater (SN-01), Vacuum Tower Charge Heater (SN-02), the Asphalt Below Charge Heater (SN-03), and the Lube Precharge Heater (SN-07); to make necessary improvement to NASH plant to ensure the sulfur content in the waste gas produced onsite remain below 0.1 gr/dscf; and to change the source descriptions for SN-07 to the "Lube Precharge Heater" and SN-30 to the "Lube Charge Heater".

The permitted emission increases were due to these modifications: 3.8 tons per year (tpy) PM/PM10, 5.8 tpy SO_2, 1.1 tpy VOC, 0.01 tpy 2,2,4-trimethylpentane, 0.18 tpy benzene, 0.01 tpy cumene, 0.01 tpy ethylbenzene, 0.34 tpy hexane, 0.06 tpy toluene, and 0.04 tpy xylene.

1227-AR-15 This permit was issued January 26, 2009. This permitting action was necessary to:

- Add two (2) 400 barrel asphalt plasticizer tanks #227 and #228 at SN-27,
- Replace three (3) 280 barrel reclaimed oil storage tanks #514, #515, and #516 (previously permitted) with three (3) reclaimed oil tanks of different size (400 barrel) and throughput at SN-27,
- Remove the 280 barrel reclaimed oil storage tank #517at SN-27,
- Add a lube oil and additive loading/unloading rack (SN-33), and
- Add a lube oil packaging operation into insignificant activities list.

The permitted emission increased due to this De Minimis modification is 0.2 tons per year (tpy) VOC. The new tanks #227, #228, #514, #515, and #516 are not subject to 40 CFR 60 Subpart Ka and Kb.

Also, Cross Oil submitted another De Minimis application on September 3, 2008 to modify its existing minor source to address the throughput at the Distillate Lube Oil Truck Loading Rack and associated storage tanks:

- Increase the throughput at the distillate lube oil storage tank (Tank # 319) from 1,302,000 gal/yr to 2,730,000 gal/yr.
- Increase the throughput at the Distillate Lube Oil loading Rack SN-31.
- Add a condition to address the throughput and tracking for the gasoline tank at SN-27.
- Record keeping requirements for SN-31 and SN-32 have been added to the permit.

The permitted emissions for SN-31 increased by: 1.2 tons per year (tpy) VOC, Benzene 0.15 tpy, Ethylbenzene 0.02 tpy, Hexane 0.3 tpy, Toluene 0.05, and Xylene 0.03 tpy.

Additionally, Cross Oil submitted a summary of all of the tanks with the revised capacities, turnovers, and emissions for Onsite Storage Tanks SN-27, Sandyland Storage Tanks SN-28, and Miller's Storage Tanks SN-29 by email dated June 26, 2008. Due to this revision the emission limits for these sources were decreased. The overall permitted emissions decreased due to this De Minimis modification by: 16.2 tpy VOC, 2,2,4-Trimethylpentane 0.06 tpy, Benzene 0.6 tpy, Cumene 0.02 tpy, Ethylbenzene 0.04 tpy, Hexane 1.02 tpy, Toluene 0.48, and Xylene 0.17 tpy.

1227-AR-16 This permit was issued March 27, 2009. This permitting action was necessary to:

- Install fourteen (14) onsite lube oil storage tanks #229, #230, #231, #232, #233, #332, #333, #334, #335, #336, #337, #338, #339, and #340 at SN-27.
- Allow the distillate to be loaded at the Asphalt Tank Car Loading Rack SN-32.

There was an increase in lube oil throughput as a result of the additional storage tanks because the tanks were being installed to allow for reduced throughput at other lube oil tanks. The introduction of distillate to SN-32 resulted in an increase of 1,500,000 gallons per year of distillate. The permitted emissions increased 1.3 ton per year (tpy) of VOC, 0.02 tpy of 2,2,4-Trimethylpentane, 0.14 tpy of Benzene, 0.01 tpy Cumene, 0.02 tpy of Hexane, 0.07 tpy of Toluene, and 0.03 tpy of Xylene.

1227-AR-17 This permit was issued on December 21, 2009. This De Minimis change was necessary to:

- Install an additional onsite distillate storage Tank #328 and lube oil storage Tanks #P033 through #P059 at SN-27
- Rename the Lube Stripper Reboiler (SN-12) to Lube Stripper Charge Heater (SN-12)
- Convert the existing lube oil storage Tanks #113 to a distillate storage tank at SN-27
- Install an offsite distillate Tank #116 at SN-29
- Install a new lube oil loading/unloading dock (SN-34)
- Change the permittee ownership and name from Cross Oil Refining and Marketing, Inc. to Martin Operating Partnership L.P.

The above listed changes may have resulted in potential emission rate increases of 0.5 ton per year (tpy) of VOC, 0.05 tpy of benzene, 0.1 tpy of hexane, 0.02 tpy of toluene, and 0.01 tpy of xylene.

1227-AR-18 This permit was issued on May 9, 2011. This permitting action was necessary to: install three new lube oil storage tanks (SN-35: Tanks #246, #341, and #342), change one existing tank from lube oil service to diesel service (SN-35: Tank #321), and correct typographical errors in the Total Allowable Emissions table. The total permitted annual emission rate limit changes associated with this De Minimis modification included: 0.4 ton per year (tpy) of VOC, 0.0003 tpy of benzene, 0.092 tpy of hexane, 0.001 tpy of toluene, and 0.0012 tpy of xylene.

1227-AR-19 This permit was issued on January 12, 2012. This permitting action was necessary to: correct the hourly permitted emission rate limits for SN-27, SN-28, and SN-29 based on the maximum hourly throughput; update the annual storage tanks throughputs; modify SN-27: removed existing Tank #100 and install a new 80,000 bbl asphalt storage tank (Tank #100), removed Tank #501 and renamed Tank #514 to Tank #501, removed Tank #502 and renamed Tank #515 to Tank #502, removed Tank #504 and installed one new 28,224 gallon reclaimed oil tank (Tank #504), removed Tank #321 from SN-27 since it is permitted under SN-35, installed three 42,301 gallon naphtha tanks (Tanks #7130, #7131, and #7132), installed one 77,400 gallon heavy condensate tank (Tank #7133), installed four new 31,500 gallon reclaimed oil tanks (Tanks #514, #515, #516, #517), changed Tanks #319 and #320 from HHD storage to lube oil, changed Tanks #312 and #329 from naphtha storage to lube oil, changed Tank #227 from asphalt storage to additive; remove Tank #116 (SN-29); rename the following sources: SN-03 to Asphalt Charge Heater (MOP will not conduct blow still operations), SN-08 to Hydrogen Plant Heater/Reformer, SN-12 to Stripper Charge Heater, SN-14 to Distillate/Naphtha Loading Rack, and SN-32 to Asphalt/Black Oil Tank Car Loading Rack; remove the Blow Still Incinerator Waste Heat Boiler SN-04 (removed from service in May 2011); route emissions from the naphtha loading (SN-14) and heavy condensate loading (SN-31) to Tanks #7130 through #7132 for naphtha and Tank #7133 for heavy condensate instead of venting to the atmosphere; revise emission limits for SN-14, SN-17, SN-18, SN-21, SN-23, SN-27, SN-28, and SN-29 to reflect site specific lube oil and distillate analysis; revise benzene emission limits for asphalt, gasoline, and crude oil storage tanks to reflect site specific analysis; install a 42,301 gallon crude oil tank (bullet tank) at the Sandyland Storage Tanks (SN-28); bubble the annual emission rate limits for the lube oil loading rack sources (SN-17, SN-18, and SN-21); bubble the annual emission limits for the Sandyland Storage Tanks (SN-28) and the Miller's Storage Tanks (SN-29); revise the emission limits at SN-32 to reflect the removal of all distillate lines; replace SN-02; add 40 CFR Part 63, Subpart CCCCCC conditions; revise reportable HAPs throughout the permit; rename the Recycle Water Evaporators in the insignificant activities list to Cooling Tower No. 1 and Cooling Tower No. 2; replace Cooling Tower No. 2 (insignificant activity A-13) with a newer model; add a new asphalt tank heater under insignificant activity A-13; and add a 50% safety factor to the pollutant content limits for SN-35 and change the HAP emission rate limits to correspond. The total permitted annual emission rate limit changes associated with this modification included: decreases of 36.6 ton per year (tpy) PM/PM_{10}, 6.3 tpy CO, 8.5 tpy NO_X, 3.7003 tpy benzene, 0.09 tpy cumene, 2.352 tpy hexane, 0.01 tpy phenol and increases of 0.2 tpy SO_2, 14.4 tpy VOC, 0.11 tpy beryllium, 0.11 tpy cadmium, 0.11 tpy chromium, 1.38 tpy ethylbenzene, 0.01 tpy methyl tert butyl ether, 0.19 tpy POM, 0.939 tpy toluene, 0.01 tpy 2,2,4-trimethylpentane, and 1.6688 tpy xylene.

1227-AR-20 This permit was issued on May 1, 2012. This permitting action was necessary to: install four new 49,250 gallon lube oil storage tanks (Tank #P060, #P061, #P062, and #P063) at SN-27, and remove Scenario #1 from SN-14, SN-27, and SN-31. The total permitted annual emission rate limits for Scenario #2 did not change with this modification.

1227-AR-21 This permit was issued November 9, 2012. This permitting action was necessary to:

- Increase the black oil production limit (SN-27: Tanks #275 through #278) from 4,872,000 gallons per year to 9,240,000 gallons per year,
- Increase the annual distillate limit for Tank #321 (SN-35) from 15,120,000 gallons per year to 26,219,328 gallons per year,
- Add distillate loading to the railcar loading source (SN-33), and
- Remove Scenario #1.

The total permitted annual emission rate increases associated with this modification included: 0.5 tons per year (tpy) VOC and 0.01 tpy hexane.

1227-AR-22 This permit was issued on May 14, 2013. This permitting action was necessary to add six lube oil storage tanks and one reclaimed oil storage tank to SN-27, to replace six existing bolted storage tanks (#247, #248, #271, #272, #273 and #27s) with three new welded storage tanks (#350, #T-343, and #T-347) in SN-27, to rebuild the existing railcar loading rack (SN-33), to add a new railcar loading rack (SN-46), to add a new Packaging Plant lube oil truck loading rack (SN-47), to add two new wastewater surge tanks (#519, #508, #510) and to remove the existing wastewater surge tank (#507) in SN-27. The permitted emissions increased by 1.2 tpy VOC. The CO_2e permitted emission limit established for sources affected by this modification was 137,710 tpy.

Permit #1227-AOP-R0 was issued on February 11, 2014. This permitting action was to allow the facility to operate as a Title V source due to the facility becoming a major source of VOC and greenhouse gas (GHG) emissions. This modification also addressed modifications to existing sources and the installation of new sources that are subject to a Prevention of Significant Deterioration (PSD) review. With this modification, the following changes occurred:

- Removal of the Lube Precharge Heater (SN-07) and the Lube Charge Heater (SN-30) both associated with the existing lube hydrotreater unit (LHT1) and install one new heater, Lube Charge Heater No. 1 (SN-36).

- Removal of the High Pressure Flare (SN-09) and Low Pressure Flare (SN-10) and install a new flare, (SN-40).
- Renaming of the existing Hydrogen Plant Heater/Reformer (SN-08) to be "Hydrogen Reformer No.1".
- Renaming of the existing Stripper Charge Heater (SN-12) to be "Stripper Charge Heater No. 1".
- Addition of the black oil loading to SN-15 and SN-16 and rename these sources:
  - Asphalt/Black Oil Truck Loading Rack No. 1 (SN-15)
  - Asphalt/Black Oil truck Loading Rack No. 2 (SN-16)
- Re-permitting all onsite storage tanks that are currently permitted as two source numbers, SN-27 and SN-35, as sources SN-27a through SN-27l, grouped according to what is stored in each tank, as follows:
  - Refinery Additives Storage Tanks (SN-27a)
  - Packaging Plant Additive Storage Tanks (SN-27b)
  - Asphalt Storage Tanks (SN-27c)
  - Black Oil Storage Tanks (SN-27d)
  - Crude Oil Storage Tank (SN-27e)
  - Untreated Distillate Storage Tanks (SN-27f)
  - Gasoline Storage Tanks (SN-27g)
  - Untreated Lube Oil Storage Tanks (SN-27h)
  - Refinery Treated Lube Oil Storage Tanks (SN-27i)
  - Packaging Plant Treated Lube Oil Storage Tanks (SN-27j)
  - Reclaim Oil Storage Tanks (SN-27k)
  - Treated Distillate Storage Tanks (SN-27l)
- Installation of new emission sources:
  - Hydrogen Reformer No. 2 (SN-37)
  - Lube Hydrotreater No. 2 Sources: Lube Charge Heater No. 2 (SN-38) and Stripper Charge Heater No. 2 (SN-39)
  - Fire Pump Engine No. 1 (SN-41)
  - Fire Pump Engine No. 2 (SN-42)
  - Fire Pump Engine No. 3 (SN-43)
- Addition of natural gas limits for the following sources.
  - Crude Charge Heater (SN-01) 250.0 MMcf/yr
  - Vacuum Charge Heater (SN-02), 63.0 MMcf/yr
  - Boiler No. 4 (SN-26), 438.0 MMcf/yr
  - Lube Charge heater No. 1 (new source, SN-36), 95.67 MMcf/yr
  - Lube Charge heater No. 2 (new source, SN-38) 167.0 MMcf/yr
  - Stripper Charge heater No. 2 (new source, SN-39), 41.30 MMcf/yr
- Changes to tanks Storage Inventory
  - Distillate tanks: Add new tanks, 120, 121, and 122. Existing lube oil tanks 206, 266, and 292 will now be distillate tanks
  - Treated Lube Oil tanks: Add new tanks 344, 345, and 346. Replace existing tanks 247, 248, 271, 272, and 274) with three new tanks,
  - New lube oil tanks: tanks 348, 349, 350, 351, 352, and 353.
  - New Packaging Plant tanks PO80, PO81, and PO82

- Relocation of the Distillate Loading Rack (SN-14). Naphtha and Heavy Condensate will continue to be loaded at the current SN-14 location; however, because of the vapor recovery system, there are no emissions associated with Naphtha and Heavy Condensate.
- Rebuilding of the loading rack SN-33 and install two new loading racks, SN-44 and SN-45 for the Packaging Plant.
- Relocation of the Lube Oil Truck Loading Rack.
- Annual NOx emissions for SN-01, SN-25, and SN-26 were previously permitted as a bubble limit. This modification assigns individual annual limits are for each sources.

Note - The Federal and Arkansas rules relating to these PSD requirements were later vacated. With this modification permitted emissions decreased by 1.0 tons/year (tpy) PM_{10} and 10.0 tpy CO. Permitted emissions increased by 1.7 tpy of PM, 12.4 tpy SO_2, 44.4 tpy VOC, 19.4 tpy NOx, 73,035.8 tpy of CO_{2e}, 0.02 tpy Acetone, and 1.22 tpy Total HAPs.

Permit #1227-AOP-R1 was issued on May 26, 2015. This permit modification was to permit, as an alternate operating scenario, the unloading of 9,500,000 gallons of heavy paraffinic oil at Miller's Bluff from barges into tanks and then loading directly into tanker trucks (Group A-3 insignificant activity). The paraffinic oil is shipped to Smackover Refinery via tanker trucks and loaded using the lube oil loading/unloading docks (SN-34) into lube oil storage tanks (SN-27j). To account for the additional tanker truck traffic, Martin requested an increase in haul road emissions (SN-46).

Additionally, the facility submitted a minor modification application on September 10, 2014 to incorporate a Surplus Loading/Unloading Rack (SN-47) which is used to load intermediate products into tanker trucks to ship offsite.

The facility also submitted a minor modification application on October 09, 2014 to install a diesel emergency generator (SN-48) to safely shut down the refinery in the event of plant power outage, maintain Wastewater Treatment Plant Operation, and provide backup power to other facility operations during an extended power outage. Also the facility installed a diesel tank for SN-48 as an insignificant activity source.

A US Supreme Court decision vacated Federal and thus Arkansas greenhouse gas (GHG) permitting rules used to permit this facility in permit 1227-AOP-R0. These GHG permit limits were removed in this permit modification.
Permitted emission increased by 0.5 tons/year (tpy) PM/PM_{10}, 1.9 tpy SO_2,3.5 tpy VOC, 5.3 tpy CO, 9.7 tpy NOx and 0.08 tpy total HAPs.

Permit #1227-AOP-R2 was issued on February 29, 2016. This permit modification was to alter the Packaging Plant Treated Lube Oil Storage Tanks (SN-27j) with the addition of a new Fuel Additive Lube Oil Storage Tank (Tank #T83) and include two 330 gallon totes of fuel additive, Fuel Additive Storage Tank A and Fuel Additive Storage Tank B, as Group A-3 Insignificant Activities.

The facility also submitted a modification application to alter the Reclaim Oil Storage Tanks (SN-27k) with the addition of two new reclaim oil tanks (Tanks #524 and #525). Additionally the facility requested to reword Plantwide Condition #11 for clarity.
Lastly, the facility submitted a minor modification application to modify the language of Specific Condition #176 to allow the flaring of excess hydrogen at the existing flare (SN-40). There are no additional air emissions expected with this modification as water vapor is the only byproduct produced from the flaring of hydrogen. Permitted annual emissions were not change as a result of these additions.

Permit #1227-AOP-R3 was issued on July 15, 2016. This permitting modification is to increase throughput limit for the Refinery Treated Lube Oil Storage Tanks (SN-27i). The permitted amount of treated lube oil throughput listed in Specific Condition #120 will increase from 82,628,700 gallons to 165,257,400 gallons. This change is due to a data entry mistake that was made in the 2013 permit modification application. The facility also submitted an administrative amendment to include four (4) Dissolved Air Flotation (DAF) skimming settling tanks to the A-3 Insignificant Activities list. Permitted annual emissions will not change as a result of these permitting actions.

Permit #1227-AOP-R4 was issued on October 31, 2016. This permitting modification was to alter the Reclaim Oil Storage Tanks bubble (SN-27k) with the replacement of Tank #512 (42,000 gallon capacity) with a larger 80,000 gallon capacity tank. This did not change the permitted emission limits.

Permit #1227-AOP-R5 was issued on September 29, 2017. This permitting action was to add a 210,000 gallon Sour Water Floating Roof Surge Tank to the facility's A-13 Insignificant Activities list. This did not result in any permitted emission increases

Permit #1227-AOP-R6 was issued March 12, 2019. This permitting action renewed the Title V permit. In addition, the facility requested the following changes:

1. Added two heaters back to the permit. These heaters were previously permitted as Lube Charge Pre-Heater (SN-07) and Hydrotreater Charge Heater (SN-30).
2. Revised calculations at SN-30 to reflect worst case emissions for burning mixed gas (refinery off gas that is mixed with pipeline quality natural gas).
3. Removed Sources SN-25, SN-36 through SN-39, SN-44 and all associated Specific/Plantwide Conditions.
4. The calculated annual emissions SN-01, SN-02, SN-03, SN-08, SN-12, SN-26, and SN-40 were revised to be based on the maximum capacity of the equipment. Fuel tracking requirements at these sources has been removed.
5. Updated the Flare (SN-40) emission calculations to reflect the final pilot designed heat input capacity of 0.255 MMBtu/hr.
6. Permited Flare (SN-40) as a process flare instead of an emergency flare.
7. Removed PW condition #11. The purpose of this condition was to verify the emission factors used in calculations. With revised calculations, more conservative emission

factors, and multiple years of testing to demonstrate compliance, this condition is no longer necessary.

8. Removed the benzene sampling requirement for SN-27c, 27e, and 27g; the purpose of this condition was to verify the emission factors used in calculations at these sources. The annual compliance sampling of these sources has consistently resulted in vapor benzene concentrations less than the detection limit at <0.0001% by weight. The emission limits for benzene and other HAPs are conservatively based on the industry average of (33.3% vapor mass fraction) within the EPA Refinery Protocol.
9. Updated emission rates for Tanks SN-27a through 27l and SN-28 based on revised calculations using EPA Emission Estimation Protocol for Petroleum Refineries and Raoult's Law.
10. Removed NSPS Subpart Kb conditions. Tank 322 (SN-27h) is not subject to this subpart because it does not meet the minimum vapor pressure for the size of the tank.
11. Removed the ability to purchase new paraffinic oil that will be loaded by barge into the Miller's Bluff Storage Tanks (SN-29). Any new purchased paraffinic oil will be shipped directly to the facility by truck.
12. Updated vapor pressure limits in Plantwide Condition #12 to reflect the revised permit limits in this application.
13. Bubbled annual emissions from the Asphalt/Black Oil Truck Loading Rack No. 1 (SN-15) and Asphalt/Black Oil Truck Loading Rack No. 2 (SN-16).
14. Removed references to NSPS Subpart GGGa, NSPS Subpart VVa and Plantwide conditions associated with these subparts. Sources subject to these subparts (SN-38 and 39) are being removed with issuance of this permit.
15. Updated emission limits at Haul Roads (SN-46) to reflect maximum facility throughput and maximum haul road distance.
16. Replaced listed HAPs with "Total HAPs" to be consistent with ADEQ's current Non-Criteria Pollutant Control Strategy. Benzene will remain listed due to Plantwide Condition #36a.
17. Updated Wastewater Emissions (SN-24) based on EPA's refinery wastewater emission estimation tool (RWET), and include H_2S emissions in the permit.

Permitted emission rates changed by 12.7 tpy PM, 2.0 tpy PM_{10}, -14.8 tpy SO_2, 54.4 tpy VOC, 13.9 tpy CO, -25.9 tpy NO_x, 2.81 tpy Benzene, 0.06 tpy Acetone, 2.20 tpy H_2S, and 16.71 tpy Total HAPs.

Permit #1227-AOP-R7 was issued on July 12, 2019. With this minor modification, the facility requested the following changes:

- Removed the Lube Charge Pre-Heater (SN-07) and NSPS Subpart J requirements for SN-07.
- Replaced the Hydrotreater Charge Heater (SN-30) burner and increase the size to 7MMBtu/hr.
- The replacement burner of the Hydrotreater Charge Heater (SN-30) was only permitted to burn natural gas. All NSPS Subpart Ja requirements were removed from the permit for SN-30.

The facility's permitted annual emissions decreased by 0.3 tpy of PM/PM_{10}, 0.7 tpy SO_2, 0.2 tpy VOC, 3.0 tpy CO, 1.8 tpy NO_x, 0.01 tpy Benzene, and 0.08 tpy Total HAPs.

SECTION IV: SPECIFIC CONDITIONS

SN-01
Crude Charge Heater

Source Description

MOP operates a crude unit that can process up to 7,700 bbl/day of crude. The crude unit is equipped with a Crude Charge Heater (SN-01) that heats the crude prior to the vacuum distillation tower. The heater has a maximum heat input rate of 32 MMBtu/hr and burns either natural gas or mixed gas (refinery off gas that is mixed with pipeline quality natural gas).

Specific Conditions

1. The permittee shall not exceed the emission rates set forth in the following table. Hourly and annual emissions are based on maximum design heat input rate. [Rule 19.501 *et seq.* and 40 C.F.R. § 52 Subpart E]

Pollutant	lb/hr	tpy
PM_{10}	0.4	1.4
SO_2	1.1	1.8
VOC	0.3	1.0
CO	3.4	14.6
NO_x	4.0	17.4

2. The permittee shall not exceed the emission rates set forth in the following table. Hourly and annual emissions are based on maximum design heat input rate. [Rule 18.801 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

Pollutant	lb/hr	tpy
PM	0.4	1.4
Benzene	0.01	0.01
Total HAPs	0.08	0.33

3. The permittee shall not exceed 5% opacity from Crude Charge Heater (SN-01) as measured by EPA Reference Method 9. Compliance with the opacity limit for SN-01 shall be demonstrated by burning natural gas mixed with refinery off gas. [Rule 18.501, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-31, and 40 C.F.R. § 52 Subpart E]

SN-02
Vacuum Tower Charge Heater

Source Description

The Vacuum Tower Charge Heater (SN-02) is the charge heater associated with the vacuum distillate tower in line with the crude unit. The heater has a maximum heat input rate of 12.6 MMBtu/hr and burns either natural gas or mixed gas (refinery off gas that is mixed with pipeline quality natural gas). The heater is subject to NSPS Subpart Ja.

Specific Conditions

4. The permittee shall not exceed the emission rates set forth in the following table. Except for SO_2, hourly and annual emissions are based on the maximum design heat input rate. The permittee shall demonstrate compliance with the SO_2 limits by compliance with Plantwide Conditions #23 through #35. [Rule 19.501 *et seq.* and 40 C.F.R. § 52 Subpart E]

Pollutant	lb/hr	tpy
PM_{10}	0.2	0.6
SO_2	0.5	0.7
VOC	0.1	0.4
CO	1.4	5.8
NO_x	1.6	6.9

5. The permittee shall not exceed the emission rates set forth in the following table. Hourly and annual emissions are based on maximum design heat input rate. [Rule 18.801 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

Pollutant	lb/hr	tpy
PM	0.2	0.6
Benzene	0.01	0.01
Total HAPs	0.03	0.13

6. The permittee shall not exceed 5% opacity from Vacuum Tower Heater (SN-02) as measured by EPA Reference Method 9. Compliance with the opacity limit for SN-02 shall be demonstrated by burning natural gas mixed with refinery off gas. [Rule 18.501, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-31, and 40 C.F.R. § 52 Subpart E]

SN-03
Asphalt Charge Heater

Source Description

The bottoms off of the Vacuum Tower are asphalt flux, which is pumped through a series of exchangers to storage and then circulated through the Asphalt Charge Heater (SN-03) to maintain tank temperature. The heater has a maximum heat input rate of 8 MMBtu/hr and burns either natural gas or mixed gas (refinery off gas that is mixed with pipeline quality natural gas).

Specific Conditions

7. The permittee shall not exceed the emission rates set forth in the following table. Hourly and annual emissions are based on the maximum design heat input rate. [Rule 19.501 *et seq.* and 40 C.F.R. § 52 Subpart E]

Pollutant	lb/hr	tpy
PM_{10}	0.1	0.4
SO_2	0.3	0.5
VOC	0.1	0.3
CO	0.9	3.7
NO_x	1.0	4.4

8. The permittee shall not exceed the emission rates set forth in the following table. Hourly and annual emissions are based on the maximum design heat input rate. [Rule 18.801 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

Pollutant	lb/hr	tpy
PM	0.1	0.4
Benzene	0.01	0.01
Total HAPs	0.02	0.09

9. Visible emissions from SN-03 shall not exceed 5% opacity as measured by EPA Reference Method 9. Compliance with the opacity limit for SN-03 shall be demonstrated by burning natural gas mixed with refinery off gas. [Rule 18.501 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

SN-08
Hydrogen Reformer No.1

Source Description

Lube oils produced by the atmospheric and vacuum distillation towers are processed in a set of heater exchangers and then are passed to the Lube Hydrotreater Unit No. 1 (LHT1). At the hydrotreaters, lube oils combine with hydrogen to make hydrotreated lube oils.

The hydrogen is supplied to LHT1 by Hydrogen Reformer No. 1 (SN-08), a steam/methane reformer. Natural gas is compressed and heated in a preheat exchanger and combined with steam. The natural gas mixture is then charged to the Hydrogen Reformer where it passes over a nickel catalyst and reacts to produce hydrogen and carbon oxides. The hydrogen reformer is equipped with a natural gas fired burner that has a maximum heat input rate of 30.0 MMBtu/hr

The gas stream from the hydrogen reformer is sent to a heat exchanger and the pressure swing absorption (PSA) system, where CO_2 and other impurities are removed from the hydrogen. The CO_2 emissions from the PSA are accounted for in the GHG emissions.

Specific Conditions

10. The permittee shall not exceed the emission rates set forth in the following table. Hourly and annual emissions are based on the maximum design heat input rate. [Rule 19.501 *et seq.* and 40 C.F.R. § 52 Subpart E]

Pollutant	lb/hr	tpy
PM_{10}	0.3	1.0
SO_2	0.1	0.1
VOC	0.2	0.8
CO	2.5	10.9
NO_x	1.5	6.5

11. The permittee shall not exceed the emission rates set forth in the following table. Hourly and annual emissions are based on the maximum design heat input rate. [Rule 18.801 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

Pollutant	lb/hr	tpy
PM	0.3	1.0
Benzene	0.01	0.01

Pollutant	lb/hr	tpy
Total HAPs	0.06	0.25

12. Visible emissions from SN-08 shall not exceed 5% opacity as measured by EPA Reference Method 9. Compliance will be demonstrated by only burning natural gas. [Rule 18.501 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

SN-12
Stripper Charge Heater No. 1

Source Description

The Stripper Charge Heater No. 1 (SN-12) is part of the Lube Hydrotreater Unit (LHT1). The lube oil from LHT1 flows to a lube oil stripper, where the remaining hydrogen sulfide is removed by steam stripping. The charge heater supplies heat to the lube oil stripper. The heater has a maximum heat input rate of 14.04 MMBtu/hr and burns either natural gas or mixed gas (refinery off gas that is mixed with pipeline quality natural gas). The heater is subject to NSPS Subpart J.

Specific Conditions

13. The permittee shall not exceed the emission rates set forth in the following table. Except for SO_2, hourly and annual emissions are based on the maximum design heat input rate. The permittee shall demonstrate compliance with the SO_2 limits by compliance with Plantwide Conditions #23 through #35. [Rule 19.501 *et seq.* and 40 C.F.R. § 52 Subpart E]

Pollutant	lb/hr	tpy
PM_{10}	0.2	0.6
SO_2	0.5	0.8
VOC	0.1	0.5
CO	1.5	6.5
NO_x	1.8	7.7

14. The permittee shall not exceed the emission rates set forth in the following table. Hourly and annual emissions are based on maximum design heat input capacity. [Rule 18.801 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

Pollutant	lb/hr	tpy
PM	0.2	0.6
Benzene	0.01	0.01
Total HAPs	0.04	0.15

15. Visible emissions from SN-12 shall not exceed 5% opacity as measured by EPA Reference Method 9. Compliance will be demonstrated by only burning natural gas mixed with refinery off gas. [Rule 18.501 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

NSPS Subpart J

16. SN-12 is subject to and shall comply with all applicable provisions of 40 CFR Part 60, Subpart J. These requirements include, but are not limited to, the following: [Rule 19.304 and 40 C.F.R. Part 60, Subpart J]

    a. SN-12 must meet the applicable provisions of 40 CFR Part 60, Subpart Ja (Plantwide Conditions #23 through #35). No further requirements apply for SN-12 under 40 CFR part 60, Subpart J. [Rule 19.304 and 40 C.F.R. §60.100(e)]

SN-14
Distillate Loading Rack

Source Description

Distillate from storage tanks (SN-27f and SN-27l) is loaded into trucks at the distillate loading rack (SN-14).

Specific Conditions

17. The permittee shall not exceed the emission rates set forth in the following table. Hourly emissions are based on pump equipment maximum. The permittee shall demonstrate compliance with annual emissions by compliance with Specific Condition #19. [Rule 19.501 *et seq.* and 40 C.F.R. § 52 Subpart E]

Pollutant	lb/hr	tpy
VOC	0.5	0.3

18. The permittee shall not exceed the emission rates set forth in the following table. Hourly emissions are based on pump equipment maximum. The permittee shall demonstrate compliance with annual emissions by compliance with Specific Condition #19 and Plantwide Condition #10. [Rule 18.801 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

Pollutant	lb/hr	tpy
Benzene	0.01	0.01
Total HAPs	0.01	0.01

19. The permittee shall not exceed a throughput of 26,219,328 gallons of distillate at SN-14 per rolling 12 month period. [Rule 19.705, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

20. The permittee shall maintain monthly records to demonstrate compliance with Specific Condition #19. The permittee shall update these records by the thirtieth day of the month following the month to which the records pertain. The twelve month rolling totals and each individual month's data shall be maintained on-site, made available to Department personnel upon request, and submitted in accordance with General Provision #7. [Rule 19.705 and 40 C.F.R. § 52 Subpart E]

SN-15 & SN-16
Asphalt/Black Oil Truck Loading Rack No.1 and
Asphalt/Black Oil Truck Loading Rack No. 2

Source Description

Asphalt from tanks (SN-27c) and black oil from tanks (SN-27d) is loaded into trucks at asphalt/black oil truck loading rack no. 1 (SN-15) and the asphalt/black oil truck loading rack no. 2 (SN-16).

Specific Conditions

21. The permittee shall not exceed the emission rates set forth in the following table. Hourly emissions are based on pump equipment maximum. The permittee shall demonstrate compliance with annual emissions by compliance with Specific Condition #23. [Rule 19.501 *et seq.* and 40 C.F.R. § 52 Subpart E]

SN	Description	Pollutant	lb/hr	tpy
15	Asphalt/Black Oil Truck Loading Rack No.1	VOC	1.1	1.2*
16	Asphalt/Black Oil Truck Loading Rack No. 2	VOC	1.1	

*Combined total for SN-15 and SN-16.

22. The permittee shall not exceed the emission rates set forth in the following table. Hourly emissions are based on pump equipment maximum. The permittee shall demonstrate compliance with annual emissions by compliance with Specific Condition #23 and Plantwide Condition #10. [Rule 18.801 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

SN	Description	Pollutant	lb/hr	tpy
15	Asphalt/Black Oil Truck Loading Rack No.1	Benzene	0.34	0.38*
		Total HAPs	0.94	1.03*
16	Asphalt/Black Oil Truck Loading Rack No. 2	Benzene	0.34	
		Total HAPs	0.94	

*Combined total for SN-15 and SN-16.

23. The permittee shall not exceed the throughputs listed in the following table. [Rule 19.705, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

Material	Throughput (gallons per rolling 12 month period)
Asphalt	19,987,800
Black Oil	9,240,000

24. The permittee shall maintain monthly records to demonstrate compliance with Specific Condition #23. The permittee shall update these records by the thirtieth day of the month following the month to which the records pertain. The twelve month rolling totals and each individual month's data shall be maintained on-site, made available to Department personnel upon request, and submitted in accordance with General Provision #7. [Rule 19.705 and 40 C.F.R. § 52 Subpart E]

SN-17, SN-18, and SN-21
Lube Oil Truck Loading Rack,
Lube Oil Truck Loading Rack,
and Lube Oil Rail Car Loading Rack
Source Description

Lube oil from storage tanks (SN-27-h and SN-27i) is loaded at the lube oil truck loading racks (SN-17 and SN-18) or the lube oil railcar loading rack (SN-21).

Specific Conditions

25. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by compliance with Specific Condition #27. [Rule 19.501 *et seq.* and 40 C.F.R. § 52 Subpart E]

SN	Description	Pollutant	lb/hr	tpy
17	Lube Oil Truck Loading Rack	VOC	0.1	0.4*
18	Lube Oil Truck Loading Rack	VOC	0.1	
21	Lube Oil Truck Loading Rack	VOC	0.2	

*Combined total for SN-17, SN-18, and SN-21

26. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by compliance with Specific Condition #27 and Plantwide Condition #10. [Rule 18.801 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

SN	Description	Pollutant	lb/hr	tpy
17	Lube Oil Truck Loading Rack	Benzene	0.01	0.01* 0.02*
		Total HAPs	0.01	
18	Lube Oil Truck Loading Rack	Benzene	0.01	
		Total HAPs	0.01	
21	Lube Oil Rail Car Loading Rack	Benzene	0.01	
		Total HAPs	0.01	

*Combined total for SN-17, SN-18, and SN-21

27. The permittee shall not exceed a throughput of 97,885,008 gallons of lube oil at SN-17, SN-18, and SN-21 combined per rolling 12 month period. [Rule 19.705, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

28. The permittee shall maintain monthly records to demonstrate compliance with Specific Condition #27. The permittee shall update these records by the thirtieth day of the month following the month to which the records pertain. The twelve month rolling totals and each individual month's data shall be maintained on-site, made available to Department personnel upon request, and submitted in accordance with General Provision #7. [Rule 19.705 and 40 C.F.R. § 52 Subpart E]

SN-23
Fugitive Emissions

Source Description

Fugitive Emissions occur through equipment leaks. SN-23 accounts for the entire facility fugitive emissions. Fugitive emissions are based on the number of valves, pump seals, compressor seals, pressure relief valves, connectors, open-ended lines, and sampling connections.

Specific Conditions

29. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by compliance with Specific Condition #31. [Rule 19.501 *et seq.* and 40 C.F.R. § 52 Subpart E]

Pollutant	lb/hr	tpy
VOC	25.7	112.5

30. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by compliance with Specific Condition #31. [Rule 18.801 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

Pollutant	lb/hr	tpy
Benzene	0.12	0.49
Total HAPs	1.62	7.07

31. The permittee shall perform an annual count of valves, pump seals, compressor seals, pressure relief valves, connectors, open-ended lines, and sampling connections shall be maintained on an annual basis. Such records shall be maintained on-site and submitted in accordance with General Provision #7. [Rule 19.705 and 40 C.F.R. § 52 Subpart E]

SN-24
Wastewater Emissions

Source Description

MOP operates an on-site wastewater treatment system to treat and discharge storm water and process water collected at the facility. The wastewater collection system consists of eight (8) process drainage areas including storm water runoff, crude unit, hydrotreater, asphalt plant, lube product storage, boiler blowdown, steam condensate, and cooling tower blowdown/makeup. The process water and storm water are pumped to the collection system surge tanks before being routed to two new covered API oil-water separators. The effluent from the API oil-water separators is routed to the dissolved air flotation (DAF) tank thence to four (4) DAF effluent tanks. From the DAF effluent tanks, the wastewater is routed through three (3) new moving bed biofilm reactors (MBBR) before being routed to a secondary DAF unit for final biological treatment. The treated wastewater is then passed through a dissolved oxygen tower before being discharged to Smackover Creek via Outfall 001. Emissions from SN-24 account for the entire wastewater collection and treatment system. The facility is subject to 40 CFR Part 61 Subpart FF (BWON MACT). The API oil-water separators are an affected facility subject to 40 CFR Part 60 Subpart QQQ.

Specific Conditions

32. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by compliance with Plantwide Condition #8. [Rule 19.501 *et seq.* and 40 C.F.R. § 52 Subpart E]

Pollutant	lb/hr	tpy
VOC	2.4	10.6

33. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by compliance with Plantwide Condition #8. [Rule 18.801 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

Pollutant	lb/hr	tpy
Acetone	0.03	0.12
Benzene	0.03	0.11
H_2S	0.74	3.24
Total HAPs	0.16	1.14

SN-26
Boiler #4

Source Description

Steam is provided to various parts of the facility by Boiler #4 (SN-26) with a maximum heat input rate of 94.3 MMBtu/hr. The boiler burns pipeline quality natural gas.

Specific Conditions

34. The permittee shall not exceed the emission rates set forth in the following table. Hourly and annual emissions are based on maximum design heat input rate. [Rule 19.501 *et seq.* and 40 C.F.R. § 52 Subpart E]

Pollutant	lb/hr	tpy
PM_{10}	0.8	3.1
SO_2	0.1	0.3
VOC	0.6	2.3
CO	7.8	34.1
NO_x	3.7	16.2

35. The permittee shall not exceed the emission rates set forth in the following table. Hourly and annual emissions are based on maximum design heat input rate. [Rule 18.801 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

Pollutant	lb/hr	tpy
PM	0.8	3.1
Benzene	0.01	0.01
Total HAPs	0.18	0.77

36. Visible emissions may not exceed 5% at SN-26 as measured by EPA Reference Method 9. Compliance will be demonstrated by burning only natural gas. [Rule 18.501 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

SN-27a
Refinery Additives Storage Tanks

Source Description

MOP stores additives in several storage tanks (SN-27a) and adds additives to the lube oil within the refinery, as needed, for quality control purposes. The additives are added through a chemical injection system. The tanks are heated with steam coils and the contents are pumped with one of two pumps each with a rated capacity of 25 gpm. The majority of these additives do not contain VOCs; however, the VOC emission limits are established to allow for operational flexibility.

Specific Conditions

37. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by compliance with Specific Condition #38. [Rule 19.501 *et seq.* and 40 C.F.R. § 52 Subpart E]

Pollutant	lb/hr	tpy
VOC	0.1	0.1

38. The permittee shall not exceed a throughput of 150,000 gallons of refinery additive at SN-27a per rolling 12 month period. [Rule 19.705, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

39. The permittee shall maintain monthly records to demonstrate compliance with Specific Condition #38. For each tank, these records shall include: the gallons per month of material produced for all tanks combined storing that material and the 12 month rolling totals of material produced for all tanks combined storing that material. The permittee shall update these records by the thirtieth day of the month following the month to which the records pertain. The twelve month rolling totals and each individual month's data shall be maintained on-site, made available to Department personnel upon request, and submitted in accordance with General Provision #7. [Rule 19.705 and 40 C.F.R. § 52 Subpart E]

SN-27b
Packaging Plant Additive Storage Tanks

Source Description

MOP stores additives in several storage tanks (SN-27b) and adds the additives to the lube oil within the packaging plant, as needed, for quality control purposes. The additives are added to the lube oil through a chemical injection system. The tanks are heated with steam coils and the contents are pumped with one of two pumps each with a rated capacity of 25 gpm. The majority of these additives do not contain VOCs; however, the VOC emission limits are established to allow for operational flexibility.

Specific Conditions

40. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by compliance with Specific Condition #41. [Rule 19.501 *et seq.* and 40 C.F.R. § 52 Subpart E]

Pollutant	lb/hr	tpy
VOC	0.1	0.1

41. The permittee shall not exceed a throughput of 500,000 gallons of additives at SN-27b per rolling 12 month period. [Rule 19.705, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

42. The permittee shall maintain monthly records to demonstrate compliance with Specific Condition #41. For each tank, these records shall include: the gallons per month of material produced for all tanks combined storing that material and the 12 month rolling totals of material produced for all tanks combined storing that material. The permittee shall update these records by the thirtieth day of the month following the month to which the records pertain. The twelve month rolling totals and each individual month's data shall be maintained on-site, made available to Department personnel upon request, and submitted in accordance with General Provision #7. [Rule 19.705 and 40 C.F.R. § 52 Subpart E]

SN-27c
Asphalt Storage Tanks

Source Description

The bottoms off the Vacuum Tower are asphalt flux, which is pumped with a rated capacity of 25 gpm through a series of exchangers to storage in several storage tanks (SN-27c). The tanks can be pumped from one storage tank to another at a maximum rate of 225 gpm; however, this is not a daily routine of moving black oil from one tank to another. The contents of the tanks are circulated through the Asphalt Charge Heater (SN-03) to maintain tank temperature. Two asphalt storage tanks 100 and 228, are subject to NSPS Subpart UU.

Specific Conditions

43. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by compliance with Specific Condition #45. [Rule 19.501 *et seq.* and 40 C.F.R. § 52 Subpart E]

Pollutant	lb/hr	tpy
VOC	0.3	0.2

44. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by compliance with Specific Condition #45. [Rule 18.801 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

Pollutant	lb/hr	tpy
Benzene	0.09	0.06
Total HAPs	0.29	0.19

45. The permittee shall not exceed a throughput of 19,987,800 gallons of asphalt at SN-27c per rolling 12 month period. [Rule 19.705, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

46. The permittee shall maintain monthly records to demonstrate compliance with Specific Condition #45. For each tank, these records shall include: the gallons per month of material produced for all tanks combined storing that material and the 12 month rolling totals of material produced for all tanks combined storing that material. The permittee shall update these records by the thirtieth day of the month following the month to which the records pertain. The twelve month rolling totals and each individual month's data shall be maintained on-site, made available to Department personnel upon request, and

submitted in accordance with General Provision #7. [Rule 19.705 and 40 C.F.R. § 52 Subpart E]

47. Tanks 100 and 228 are subject to Subpart UU. Within 60 days after achieving the maximum production rate, but not later than 180 days after initial startup of such facility, the permittee shall not cause to be discharged into the atmosphere from any asphalt storage tank exhaust gases with opacity greater than 0 percent, except for one consecutive 15-minute period in any 24-hour period when the transfer lines are being blown for clearing. The control device shall not be bypassed during this 15-minute period. [Rule 19.304 and 40 C.F.R. § 60.472(c)]

48. The permittee shall use Method 9 and the procedures in §60.11 to determine opacity for tanks 100 and 228. [Rule 19.304 and 40 C.F.R. § 60.474(c)(5)]

SN-27d
Black Oil Storage Tanks

Source Description

Black oil is approximate 20% asphalt and 80% heavy lube oil. Black oil is pumped into several tanks (SN-27d) at a rate of approximately 9 gpm when the asphalt production line is filled. The tanks can be pumped from one storage tank to another at a maximum rate of 240 gpm; however, this is not a daily routine of moving black oil from one tank to another. The tanks are heated with steam coils.

Specific Conditions

49. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by compliance with Specific Condition #51. [Rule 19.501 *et seq.* and 40 C.F.R. § 52 Subpart E]

Pollutant	lb/hr	tpy
VOC	0.9	0.3

50. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by compliance with Specific Condition #51. [Rule 18.801 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

Pollutant	lb/hr	tpy
Benzene	0.30	0.10
Total HAPs	0.88	0.27

51. The permittee shall not exceed a throughput of 9,240,000 gallons of black oil at SN-27d per rolling 12 month period. [Rule 19.705, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

52. The permittee shall maintain monthly records to demonstrate compliance with Specific Condition #51. For each tank, these records shall include: the gallons per month of material produced for all tanks combined storing that material and the 12 month rolling totals of material produced for all tanks combined storing that material. The permittee shall update these records by the thirtieth day of the month following the month to which the records pertain. The twelve month rolling totals and each individual month's data shall be maintained on-site, made available to Department personnel upon request, and submitted in accordance with General Provision #7. [Rule 19.705 and 40 C.F.R. § 52 Subpart E]

SN-27e
Crude Oil Storage Tanks

Source Description

MOP processes produced naphthenic crude oil into naphtha, distillate, lube oils, and asphalt. The crude oil is stored in two large storage tanks, Tank 109 and Tank 113, with a total capacity of 2,100,000 gal. Crude oil from Sandyland storage tanks (SN-28) is pumped to Tank 109 and Tank 113.

Specific Conditions

53. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by compliance with Specific Condition #55. [Rule 19.501 *et seq.* and 40 C.F.R. § 52 Subpart E]

Pollutant	lb/hr	tpy
VOC	5.6	7.9

54. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by compliance with Specific Condition #55 . [Rule 18.801 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

Pollutant	lb/hr	tpy
Benzene	0.33	0.47
Total HAPs	0.61	0.87

55. The permittee shall not exceed a throughput of 118,041,000 gallons of crude oil at SN-27e per rolling 12 month period. [Rule 19.705, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

56. The permittee shall maintain monthly records to demonstrate compliance with Specific Condition #55. For each source and each material, these records shall include: the gallons per month of material produced for all tanks combined storing that material and the 12 month rolling totals of material produced for all tanks combined storing that material. The permittee shall update these records by the thirtieth day of the month following the month to which the records pertain. The twelve month rolling totals and each individual month's data shall be maintained on-site, made available to Department personnel upon request, and submitted in accordance with General Provision #7. [Rule 19.705 and 40 C.F.R. § 52 Subpart E]

SN-27f
Untreated Distillate Storage Tank

Source Description

MOP stores untreated distillate in several storage tanks (SN-27f). MOP fills only one tank at a time from the distillate production unit at a rate of 50 gpm. From the storage tank they feed untreated distillate to the hydrotreater at a rate of 375 gpm.

Specific Conditions

57. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by compliance with Specific Condition #59. [Rule 19.501 *et seq.* and 40 C.F.R. § 52 Subpart E]

Pollutant	lb/hr	tpy
VOC	0.8	0.6

58. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by compliance with Specific Condition #59 and Plantwide Condition #10. [Rule 18.801 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

Pollutant	lb/hr	tpy
Benzene	0.01	0.01
Total HAPs	0.02	0.01

59. The permittee shall not exceed a throughput of 26,219,328 gallons of untreated distillate at SN-27f per rolling 12 month period. [Rule 19.705, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

60. The permittee shall maintain monthly records to demonstrate compliance with Specific Condition #59. The permittee shall update these records by the thirtieth day of the month following the month to which the records pertain. The twelve month rolling totals and each individual month's data shall be maintained on-site, made available to Department personnel upon request, and submitted in accordance with General Provision #7. [Rule 19.705 and 40 C.F.R. § 52 Subpart E]

SN-27g
Gasoline Storage Tank

Source Description

MOP stores purchased gasoline in one storage tank (SN-27g). Gasoline is delivered to the plant in 4,200-gallon tanker trucks.

Specific Conditions

61. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by compliance with Specific Condition #63. [Rule 19.501 *et seq.* and 40 C.F.R. § 52 Subpart E]

Pollutant	lb/hr	tpy
VOC	38.7	1.0

62. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by compliance with Specific Condition #63. [Rule 18.801 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

Pollutant	lb/hr	tpy
Benzene	0.31	0.01
Total HAPs	7.52	0.19

63. The permittee shall not exceed a throughput of 24,066 gallons of gasoline at SN-27g per rolling 12 month period. [Rule 19.705, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

64. The permittee shall maintain monthly records to demonstrate compliance with Specific Condition #63. The permittee shall update these records by the thirtieth day of the month following the month to which the records pertain. The twelve month rolling totals and each individual month's data shall be maintained on-site, made available to Department personnel upon request, and submitted in accordance with General Provision #7. [Rule 19.705 and 40 C.F.R. § 52 Subpart E]

NESHAP CCCCCC Conditions

65. The gasoline tank at SN-27g is subject to 40 CFR Part 63, Subpart CCCCCC. The permittee shall comply with all applicable provisions of 40 CFR Part 63, Subpart CCCCCC which includes, but is not limited to the following: [Rule 19.304 and 40 C.F.R. §63, Subpart CCCCCC]

   a. The permittee shall keep records to demonstrate that the monthly gasoline throughput is less than 10,000 gallons. These records shall be kept for a period of 5 years. [Rule 19.304 and 40 C.F.R. §63.11111]
   b. The permittee must, at all times, operate and maintain any affected source in a manner consistent with safety and good air pollution control practices for minimizing emissions. [Rule 19.304 and 40 C.F.R. §63.11115(a)]
   c. The permittee must not allow gasoline to be handled in a manner that would result in vapor releases to the atmosphere for extended periods of time. Measures to be taken include, but are not limited to, the following: [Rule 19.304 and 40 C.F.R. §63.11116(a)]
      i. Minimize gasoline spills;
      ii. Clean up spills as expeditiously as practicable;
      iii. Cover all open gasoline containers and all gasoline storage tank fill-pipes with a gasketed seal when not in use;
      iv. Minimize gasoline sent to open waste collection systems that collect and transport gasoline to reclamation and recycling devices, such as oil/water separators.
   d. The permittee is not required to submit notifications or reports as specified in 40 CFR §63.11125, §63.11126, or Subpart A, but the permittee must have records available within 24 hours of a request by the Administrator to document the gasoline throughput. [Rule 19.304 and 40 C.F.R. §63.11116(b)]

SN-27h
Untreated Lube Oil Storage Tank

Source Description

MOP stores untreated lube oil in several tanks (SN-27h). MOP fills one tank at a time from the production line at a rate of 150 gpm. Some of lube oils are blended together, which means they may pump lube oil from one tank to another tank to blend the lube oils. MOP has three pumps, each with a pumping rate of 225 gpm, to pump lube oil from one tank to another.

Specific Conditions

66. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by compliance with Specific Condition #68. [Rule 19.501 *et seq.* and 40 C.F.R. § 52 Subpart E]

Pollutant	lb/hr	tpy
VOC	0.3	0.3

67. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by compliance with Specific Condition #68 and Plantwide Condition #10. [Rule 18.801 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

Pollutant	lb/hr	tpy
Benzene	0.01	0.01
Total HAPs	0.02	0.02

68. The permittee shall not exceed a throughput of 82,628,700 gallons of untreated lube oil at SN-27h per rolling 12 month period. [Rule 19.705, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

69. The permittee shall maintain monthly records to demonstrate compliance with Specific Condition #68. The permittee shall update these records by the thirtieth day of the month following the month to which the records pertain. The twelve month rolling totals and each individual month’s data shall be maintained on-site, made available to Department personnel upon request, and submitted in accordance with General Provision #7. [Rule 19.705 and 40 C.F.R. § 52 Subpart E]

SN-27i
Refinery Treated Lube Oil Storage Tanks

Source Description

MOP stores treated lube oil at the refinery in several storage tanks (SN-27i). MOP fills one tank at a time from the hydrotreated production line at a rate of 150 gpm. Some of the lube oils are blended together, which means they may pump lube oil from one tank to another tank to blend the lube oils. MOP has three pumps each with a pumping rate of 225 gpm, to pump lube oil from one tank to another.

Specific Conditions

70. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by compliance with Specific Condition #72. [Rule 19.501 *et seq.* and 40 C.F.R. § 52 Subpart E]

Pollutant	lb/hr	tpy
VOC	0.4	0.7

71. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by compliance with Specific Condition #72 and Plantwide Condition #10. [Rule 18.801 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

Pollutant	lb/hr	tpy
Benzene	0.01	0.01
Total HAPs	0.02	0.03

72. The permittee shall not exceed a throughput of 165,257,400 gallons of treated lube oil at SN-27i per rolling 12 month period. [Rule 19.705, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

73. The permittee shall maintain monthly records to demonstrate compliance with Specific Condition #72. The permittee shall update these records by the thirtieth day of the month following the month to which the records pertain. The twelve month rolling totals and each individual month's data shall be maintained on-site, made available to Department personnel upon request, and submitted in accordance with General Provision #7. [Rule 19.705 and 40 C.F.R. § 52 Subpart E]

SN-27j
Packaging Plant Treated Lube Oil Storage Tanks

Source Description

MOP stores treated lube oil at the packaging plant in several storage tanks (SN-27j). MOP fills at most four tanks at one time in the packaging plant area. MOP can fill three tanks at a time from the Refinery, each tank using pumps at a rate of 225 gpm and fill a tank by truck during the same period.

Specific Conditions

74. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by compliance with Specific Condition #76. [Rule 19.501 *et seq.* and 40 C.F.R. § 52 Subpart E]

Pollutant	lb/hr	tpy
VOC	0.3	0.3

75. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by compliance with Specific Condition #76 and Plantwide Condition #10. [Rule 18.801 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

Pollutant	lb/hr	tpy
Benzene	0.01	0.01
Total HAPs	0.01	0.01

76. The permittee shall not exceed the throughputs set forth in the following table at SN-27j and SN-29 per rolling 12 month period. [Rule 19.705, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

SN	Description	gal/12 month period
27j	Treated Lube Oil	60,000,000
29	Paraffinic Oil	9,500,000

77. The permittee shall maintain monthly records to demonstrate compliance with Specific Condition #76. The permittee shall update these records by the thirtieth day of the month following the month to which the records pertain. The twelve month rolling totals and each individual month's data shall be maintained on-site, made available to Department personnel upon request, and submitted in accordance with General Provision #7. [Rule 19.705 and 40 C.F.R. § 52 Subpart E]

SN-27k
Reclaim Oil Storage Tanks

Source Description

MOP stores reclaimed oil from the waste water treatment system in several storage tanks (SN-27k). MOP fills one tank at a time from the waste water treatment system at a pump rate of 100 gpm.

Specific Conditions

78. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by compliance with Specific Condition #80. [Rule 19.501 *et seq.* and 40 C.F.R. § 52 Subpart E]

Pollutant	lb/hr	tpy
VOC	0.3	0.2

79. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by compliance with Specific Condition #80 and Plantwide Condition #10. [Rule 18.801 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

Pollutant	lb/hr	tpy
Benzene	0.01	0.01
Total HAPs	0.01	0.01

80. The permittee shall not exceed a throughput of 4,035,229 gallons of reclaimed oil at SN-27k per rolling 12 month period. [Rule 19.705, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

81. The permittee shall maintain monthly records to demonstrate compliance with Specific Condition #80. The permittee shall update these records by the thirtieth day of the month following the month to which the records pertain. The twelve month rolling totals and each individual month's data shall be maintained on-site, made available to Department personnel upon request, and submitted in accordance with General Provision #7. [Rule 19.705 and 40 C.F.R. § 52 Subpart E]

SN-27l
Treated Distillate Storage Tank

Source Description

MOP stores treated distillate in one storage tank (Tank 121, SN-27l). Normal operations would be to fill the tank from the hydrotreater, and then from the storage tank, the distillate is sent to the loading rack.

Specific Conditions

82. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by compliance with Specific Condition #84. [Rule 19.501 *et seq.* and 40 C.F.R. § 52 Subpart E]

Pollutant	lb/hr	tpy
VOC	0.6	0.6

83. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by compliance with Specific Condition #84 and Plantwide Condition #10. [Rule 18.801 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

Pollutant	lb/hr	tpy
Benzene	0.01	0.01
Total HAPs	0.01	0.01

84. The permittee shall not exceed a throughput of 26,219,328 gallons of treated distillate at SN-27l per rolling 12 month period. [Rule 19.705, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

85. The permittee shall maintain monthly records to demonstrate compliance with Specific Condition #84. The permittee shall update these records by the thirtieth day of the month following the month to which the records pertain. The twelve month rolling totals and each individual month's data shall be maintained on-site, made available to Department personnel upon request, and submitted in accordance with General Provision #7. [Rule 19.705 and 40 C.F.R. § 52 Subpart E]

SN-28 & SN-29
Sandyland Storage Tanks and
Miller's Storage Tanks

Source Description

Trucks deliver locally produced and Grade A crude oil daily to the tanks at Sandyland (SN-28). Emissions from unloading of crude oil from trucks into the Sandyland and Miller's Bluff storage tanks are accounted for in the working losses estimated within SN-28 and SN-29.

At Sandyland, trucks are off loaded to Tank 110 or Tank 111. Tanks 110 and 111 feed the refinery (Tank 109 and Tank 113).

At Miller's Bluff, trucks off load to Tank 114 and Tank 115. These tanks feed crude oil to Sandyland.

Specific Conditions

86. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by complying with Specific Condition #88. [Rule 19.501 *et seq.* and 40 C.F.R. § 52 Subpart E]

SN	Description	Pollutant	lb/hr	tpy
28	Sandyland Storage Tanks	VOC	12.1	17.8
29	Miller's Storage Tanks	VOC	4.1	4.4

87. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by complying with Specific Condition #88 and Plantwide Condition #10. [Rule 18.801 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

SN	Description	Pollutant	lb/hr	tpy
28	Sandyland Storage Tanks	Benzene	0.72	1.06
		Total HAPs	1.33	1.96
29	Miller's Storage Tanks	Benzene	0.01	0.01
		Total HAPs	0.21	0.23

88. The permittee shall not exceed the throughputs set forth in the following table at SN-28 and SN-29 per rolling 12 month period. [Rule 19.705, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

SN	Description	gal/12 month period
28	Crude Oil	118,041,000
29	Crude Oil	5,000,000

89. The permittee shall maintain monthly records to demonstrate compliance with Specific Condition #88. The permittee shall update these records by the thirtieth day of the month following the month to which the records pertain. The twelve month rolling totals and each individual month's data shall be maintained on-site, made available to Department personnel upon request, and submitted in accordance with General Provision #7. [Rule 19.705 and 40 C.F.R. § 52 Subpart E]

SN-30
Hydrotreater Charge Heater

Source Description

The lube oils produced by both atmospheric and vacuum distillation are further processed in a set of exchangers and then passed to the hydrotreaters. The oils are heated with heat exchangers and a Hydrotreater Charge Heater (SN-30), before being pumped into the top of each reactor. The hot lube oils combine with hydrogen at the top of each reactor before passing through a catalyst bed. Sulfur in the oil reacts with the hydrogen to form hydrogen sulfide gas. The hydrogen sulfide gas also saturates the aromatic compounds in the oil, removes heavy metals, and converts some nitrogen to ammonia. The Hydrotreater Charge Heater (SN-30) has maximum heat input rate of 7 MMBtu/hr and burns only pipeline quality natural gas.

Specific Conditions

90. The permittee shall not exceed the emission rates set forth in the following table. Hourly and annual emissions are based on the maximum design heat input rate. [Rule 19.501 *et seq.* and 40 C.F.R. § 52 Subpart E]

Pollutant	lb/hr	tpy
PM_{10}	0.1	0.3
SO_2	0.1	0.1
VOC	0.1	0.2
CO	0.6	2.6
NO_x	0.4	1.6

91. The permittee shall not exceed the emission rates set forth in the following table. Hourly and annual emissions are based on the maximum design heat input rate. [Rule 18.801 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

Pollutant	lb/hr	tpy
PM	0.1	0.3
Benzene	0.01	0.01
Total HAPs	0.02	0.06

92. Visible emissions from SN-30 shall not exceed 5% opacity as measured by EPA Reference Method 9. Compliance with the opacity limit for SN-30 shall be demonstrated by burning natural gas only. [Rule 18.501 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

SN-32
Asphalt/Black Oil Tank Car Loading Rack

Source Description

Asphalt from the asphalt tanks (SN-27c) and black oil from the black oil tanks (SN-27d) is loaded into trucks at the asphalt/black oil tank car loading rack (SN-32).

Specific Conditions

93. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by complying with Specific Condition #45 and Specific Condition #51. [Rule 19.501 *et seq.* and 40 C.F.R. § 52 Subpart E]

Pollutant	lb/hr	tpy
VOC	1.1	1.2

94. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by complying with Specific Condition #45 and Specific Condition #51. [Rule 18.801 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

Pollutant	lb/hr	tpy
Benzene	0.34	0.38
Total HAPs	1.11	1.24

SN-33
Lube Oil & Distillate Rail Car Loading and Additive Railcar Unloading

Source Description

Lube oil from the lube oil storage tanks (SN-27h and SN-27i) and distillate from the distillate storage tanks (SN-27f and SN-27l) are loaded into railcars at the loading rack (SN-33). Additives are also unloaded by railcar at the loading racks (SN-33) into the additives tanks (SN-27a and SN-27b).

Specific Conditions

95. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by compliance with Specific Condition #59 and Specific Condition #68. [Rule 19.501 *et seq.* and 40 C.F.R. § 52 Subpart E]

Pollutant	lb/hr	tpy
VOC	1.0	0.8

96. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by compliance with Specific Condition #59 and Specific Condition #68. [Rule 18.801 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

Pollutant	lb/hr	tpy
Benzene	0.01	0.01
Total HAPs	0.02	0.02

SN-34
Packaging Plant Lube Oil Loading/Unloading Docks

Source Description

Crude oil at the Millers Bluff Tanks (SN-29) may be loaded onto trucks at the Miller's Bluff Unloading Rack (Group A-13 Insignificant Activity). Purchased paraffinic oils and lube oils are unloaded at the packaging plant loading docks (SN-34). Lube oil from the lube oil tanks (SN-27j) are loaded at the packaging plant loading docks (SN-34).

Specific Conditions

97. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by with Specific Condition #76. [Rule 19.501 *et seq.* and 40 C.F.R. § 52 Subpart E]

Pollutant	lb/hr	tpy
VOC	0.2	0.3

98. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by compliance with Specific Condition #76. [Rule 18.801 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

Pollutant	lb/hr	tpy
Benzene	0.01	0.01
Total HAPs	0.02	0.02

SN-40
Flare

Source Description

The Flare (SN-40) operates to control fuel gases from the Crude Unit and hydrogen from the Hydrogen Reformer. The controlled gases are from normal operation of the refinery and from emergency releases. The flare is steam aspirated "smokeless" and utilizes a 0.255 MMBtu/hr pipeline natural gas pilot. The flare is subject to NSPS Subpart Ja.

Specific Conditions

99. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by compliance with Specific Condition #102 and Plantwide Conditions #14 through #30. [Rule 19.501 *et seq.* and 40 C.F.R. § 52 Subpart E]

Pollutant	lb/hr	tpy
PM_{10}	0.1	0.1
SO_2	79.5	2.5
VOC	1592.2	17.2
CO	747.9	8.5
NO_x	164.1	1.9

100. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by compliance with Specific Condition #102 and Plantwide Conditions #14 through #30. [Rule 18.801 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

Pollutant	lb/hr	tpy
PM	0.1	0.1
Benzene	0.02	0.07
H_2S	0.43	0.01
Total HAP	0.08	0.34

101. The permittee shall conduct daily observations of the opacity at SN-40 and keep a record of these observations. The flare (SN-40) shall be designed for and operated with no visible emissions, except for periods not to exceed a total of five (5) minutes during any two (2) consecutive hours. EPA Reference Methods 22 shall be used to determine compliance with the visible emission provisions of the flare. If the permittee detects visible emissions in excess of their permitted limit, the permittee must immediately take action to identify and correct the cause of the visible emissions. After implementing the corrective action, the permittee must document that the source complies with the visible emissions requirements. The permittee shall maintain records of the cause of the visible emissions and the corrective action taken. The permittee must keep these records onsite and make them available to Department personnel upon request. [Rule 18.501 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

102. The total flow of NSPS Ja quality process gas to the flare shall be limited to 130 MMscf per rolling 12 month period. The following flared gases are not counted against this limit. [Rule 19.705, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

   a. Flaring of hydrogen gas from the hydrogen plant, when no other process gas is flared.
   b. Combustion of natural gas in the pilot.
   c. Flaring of gas during upset conditions reported in Specific Condition #105

103. The permittee shall maintain monthly records to demonstrate compliance with Specific Condition #102. The permittee shall update these records by the thirtieth day of the month following the month to which the records pertain. The twelve month rolling totals and each individual month's data shall be maintained on-site, made available to Department personnel upon request, and submitted in accordance with General Provision #7. [Rule 19.705 and 40 C.F.R. § 52 Subpart E]

104. The permittee must operate the flare (SN-40) pilot flame within the design limitations and manufacturer's specifications. [Reg.19.303 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

105. If the flare is used in an upset, emergency condition, startup, shutdown, or malfunction the permittee shall report the upset (by telephone, facsimile, or overnight delivery) to the Department by then end of the next business day after the occurrence or discovery of the occurrence. The permittee shall submit to the Department, within five business days after the occurrence or the discovery of the occurrence, a full, written report of such occurrence, including a statement of all known causes and of the scheduling and nature of the actions to be taken to minimize or eliminate future occurrences, including, but not limited to, action to reduce the frequency of occurrence of such conditions, to minimize the amount by which said limits are exceeded, and to reduce the length of time for which said limits are exceeded. If the information is included in the initial report, it need not be

submitted again. [Reg.19.601 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

106. The permittee shall during each scheduled plant shutdown, but no more than 24 months apart, calibrate and perform preventative maintenance. In accordance with manufacturer's specification, the permittee shall ensure the flare operates with efficient combustion control and shall implement procedures to minimize the amount of carbon in the unburned gas stream through steps including proper burner turning and the use of natural gas as the combustion fuel. The permittee shall maintain documentation on-site and records shall be made available to Department personnel upon request. [Rule 19.703, 40 C.F.R. § 52 Subpart E, and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

CAM Plan for Flare (SN-40)

107. The Flare (SN-40) must have a flame present at all times of operation. The presence of a flare pilot light shall be monitored continuously using a thermocouple, an ultraviolet sensor or any other equivalent device to detect the presence of a flame. In the event of a flame failure, the permittee shall maintain and follow emergency procedures until the flame is present again. The permittee shall report all upset conditions to the Department by the end of the next business day after the discovery of the occurrence. [Rule 19.703, 40 C.F.R § 52 Subpart E, and 40 C.F.R. § 64.6]

108. The permittee shall install and operate alarm system to notify the operator of the presence of a pilot flame or other possible flare malfunction. The permittee shall perform monthly visual confirmation of the pilot lights, semi-annually remove the strainer and check for debris, and annual test fire to ensure pilot light. The permittee shall maintain logs of all flare inspection and maintenance activities. These logs shall be kept on site, in accordance with General Provision 7, and made available to Department personnel upon request. [Rule 19.703, 40 C.F.R § 52 Subpart E, and 40 C.F.R. § 64.6(c)(1)]

SN-41, SN-42, SN-43, and SN-48
Fire Pump Engine No.1, No.2, No.3
and Emergency Generator Engine

Source Description

The 327 hp Fire Pump Engine No.1 (SN-41), 169 hp Fire Pump Engine No. 2 (SN-42), and 327 hp Fire Pump Engine No. 3 (SN-43) are diesel fired fire pump engines used to supply water to the refinery in the event of a fire. The 3,673 hp Emergency Generator Engine (SN-48) is a diesel fired generator used primarily to safely shut down the refinery in the event of a plant power outage. It is also used to maintain the wastewater treatment plant operation and provide backup power to other facility operations during an extended power outage. All four engines are subject to NESHAP Subpart ZZZZ and SN-41, SN-43, and SN-48 are also subject to NSPS Subpart IIII.

Specific Conditions

109. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by compliance with Specific Condition #111, #113, #123, and #124. [Rule 19.501 *et seq.* and 40 C.F.R. § 52 Subpart E]

SN	Description	Pollutant	lb/hr	tpy
41	Fire Pump Engine No. 1	PM_{10}	0.1	0.1
		SO_2	0.7	0.2
		VOC	0.9	0.3
		CO	1.1	0.3
		NO_x	1.6	0.4
42	Fire Pump Engine No. 2	PM_{10}	0.4	0.1
		SO_2	0.4	0.1
		VOC	0.5	0.2
		CO	1.2	0.3
		NO_x	5.3	1.4
43	Fire Pump Engine No. 3	PM_{10}	0.1	0.1
		SO_2	0.7	0.2
		VOC	0.9	0.3
		CO	1.1	0.3

SN	Description	Pollutant	lb/hr	tpy
		NO_x	1.6	0.4
48	Emergency Generator Engine	PM_{10}	1.3	0.4
		SO_2	0.1	0.1
		VOC	2.4	0.6
		CO	21.2	5.3
		NO_x	38.7	9.7

110. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by compliance with Specific Condition #111, #113, #123, and #124. [Rule 18.801 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

SN	Description	Pollutant	lb/hr	tpy
41	Fire Pump Engine No. 1	PM	0.1	0.1
		Benzene	0.01	0.01
		Total HAPs	0.01	0.01
42	Fire Pump Engine No. 2	PM	0.4	0.1
		Benzene	0.01	0.01
		Total HAPs	0.01	0.01
43	Fire Pump Engine No. 3	PM	0.1	0.1
		Benzene	0.01	0.01
		Total HAPs	0.01	0.01
48	Emergency Generator Engine	PM	1.3	0.4
		Benzene	0.02	0.01
		Total HAPs	0.05	0.02

111. The permittee shall not exceed 20% opacity from SN-41, SN-42, SN-43and SN-48 as measured by EPA Reference Method 9. Compliance with this Specific Condition shall be demonstrated by compliance with Specific Condition #112. [Rule 19.503 and 40 C.F.R. § 52 Subpart E]

112. Annual observations of the opacity from SN-41, SN-42, SN-43 and SN-48 shall be conducted by a person trained but not necessarily certified in EPA Reference Method. If visible emissions in excess of the permitted levels are detected, the permittee shall immediately take action to identify the cause of the visible emissions in excess of the permit limit, implement corrective action, and document that visible emissions did not appear to be in excess of the permitted opacity following the corrective action. The permittee shall maintain records which contain the following items in order to demonstrate compliance with this specific condition. These records shall be updated annually kept on site, and made available to Department personnel upon request. [Rule 19.503 and 40 C.F.R. § 52 Subpart E]

   a. The date and time of the observation.
   b. If visible emissions which appeared to be above the permitted limit were detected.
   c. If visible emissions which appeared to be above the permitted limit were detected, the cause of the exceedance of the opacity limit, the corrective action taken, and if the visible emissions appeared to be below the permitted limit after the corrective action was taken.
   d. The name of the person conducting the opacity observations.

113. The permittee shall not operate any of the emergency generators SN-41, SN-42, SN-43, and SN-48 in excess of 500 total hours (emergency and non-emergency) per calendar year in order to demonstrate compliance with the annual emission rate limits. Emergency operation in excess of these hours may be allowable but shall be reported and will be evaluated in accordance with Regulation 19 §19.602 and other applicable regulations. [Rule 19.705, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

114. The permittee shall maintain monthly records to demonstrate compliance with Specific Condition #113. The permittee shall update these records by the thirtieth day of the month following the month to which the records pertain. The calendar year totals and each individual month's data shall be maintained on-site, made available to Department personnel upon request, and submitted in accordance with General Provision #7. [Rule 19.705 and 40 C.F.R. § 52 Subpart E]

SN-42: NEHSAP Subpart ZZZZ

115. The permittee shall meet the following requirements of Table 2d of 40 CFR Part 63 Subpart ZZZZ: [Rule 19.304 and 40 C.F.R. § 63.6603(a)]

   a. Change oil and filter every 500 hours of operation or annually, whichever comes first.
   b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first.
   c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.

116. The permittee shall operate and maintain SN-42 according to the manufacturer's emission-related written instructions or develop maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions. [Rule 19.304 and 40 C.F.R. § 63.6625(e)

117. The permittee shall install a non-resettable hour meter if one is not already installed at SN-42. [Rule 19.304 and 40 C.F.R. § 63.6625(f)]

118. The permittee shall minimize the engines time spent at idle during startup and minimize the engines startup time to a period needed for appropriate and safe loading of the engines, not to exceed 30 minutes, after which time the emission standards applicable to all times other than startup in Table 2c of 40 CFR Part 63 Subpart ZZZZ apply. [Rule 19.304 and 40 C.F.R. § 63.6625(h)]

119. The permittee may operate the emergency stationary RICE engines for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by Federal, State, or local government, the manufacturer, the vendor or the insurance company associated with the engine. Maintenance checks and readiness testing of such units is limited to 100 hours per year. SN-42 may be operated up to 50 hours per year in non-emergency situations, but those hours per year are counted towards the 100 hours per year provided for maintenance and testing. The hours cannot be used for peak shaving or to generate income for the facility to supply power to the electric grid or otherwise supply power as part of a financial arrangement with another entity. There are no time limits for the use of an emergency stationary RICE in emergency situations. The engines may not be operated for more than 30 minutes prior to the time when the emergency conditions expected to occur, and the engines operation must be terminated immediately after the facility is notified that the emergency condition is no longer imminent. [Rule 19.304 and 40 C.F.R. § 63.6640(f)(4)]

120. The permittee shall submit deviations to 40 CFR Part 63 Subpart ZZZZ in the semiannual monitoring report and annual compliance report. [Rule 19.304 and 40 C.F.R. § 63.6650(f)]

121. The permittee shall keep records of the maintenance conducted on SN-42 in order to demonstrate that they were operated and maintained according to the maintenance plan. [Rule 19.304 and 40 C.F.R. § 63.6655(e)(2)]

122. The permittee shall keep records of the hours of operation of the engines that is recorded through the non-resettable hour meter. The permittee must document how many hours are spent for emergency operation; including what classified the operation as emergency and how many hours are spent for non-emergency operation. If the engines are used for demand response operation, records of notification of the emergency situation, and the time the engines were operated as part of demand response. [Rule 19.304 and 40 C.F.R. § 63.6655(f)(2)]

123. The permittee shall maintain files of all information required by 40 CFR Part 63 Subpart ZZZZ recorded in a form suitable and readily available for expeditious inspection and review. The files shall be retained for at least 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record. At a minimum, the most recent 2 years of data shall be retained on site. [Rule 19.304 and 40 C.F.R. § 63.6660]

SN-41, SN-43 and SN-48: NSPS Subpart IIII

124. The permittee shall comply with and maintain the emission standards as outlined in the following table for all pollutants over the entire life of the engine. [Rule 19.304 and 40 C.F.R. § 60.4205(b), (c), § 60.4206]

SN	Emission Standard
SN-41, SN-43	Table 4 of 40 CFR Part 60, Subpart IIII
SN-48	40 CFR 89.112 and 40 CFR 89.113

125. The permittee shall only use diesel fuel that meets the requirements of 40 CFR §80.510 (b). [Rule 19.304 and 40 C.F.R. § 60.4207(b)]

126. The permittee shall install a non-resettable hour meter prior to startup of the engines. [Rule 19.304 and 40 C.F.R. § 60.4209(a)]

127. The permittee shall demonstrate compliance with the emission standards in Subpart IIII by complying with the following: [Rule 19.304 and 40 C.F.R. § 60.4211(a)(1)(2)(3)]

a. Operate and maintain SN-41, SN-43 and SN-48 according to the manufacturer's emission-related written instructions;
b. Change only those emission related settings that are permitted by the manufacturer; and
c. Meet the requirements of 40 CFR parts 89, 94, and/or 1068, as applicable.

128. The permittee may operate the engine for the purpose of maintenance checks and readiness testing, provided that the tests are recommended, for a maximum of 100 hours per year. The engines may be operated up to 50 hours per year in non-emergency situation, but those hours are counted towards the 100 hours per year provided for maintenance and testing. [Rule 19.304 and 40 C.F.R. § 60.4211(f)]

129. If the permittee does not install, configure, operate, and maintain SN-41, SN-43 and SN-48 according to the manufacturer's emission related written instructions, or if the permittee changes emission related settings in a way that is not permitted by the manufacturer, the permittee shall demonstrate compliance through compliance with §40.4211(g). [Rule 19.304 and 40 C.F.R. § 60.4211 (g)]

SN-45
Packaging Plant Truck Loading and Unloading Rack

Source Description

Lube oil from the lube oil tanks (SN-27j) are loaded at the packaging plant truck loading rack (SN-45).

Specific Conditions

130. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by compliance with Specific Condition #132. [Rule 19.501 *et seq.* and 40 C.F.R. § 52 Subpart E]

Pollutant	lb/hr	tpy
VOC	0.1	0.2

131. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by compliance with Specific Condition #132. [Rule 18.801 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

Pollutant	lb/hr	tpy
Benzene	0.01	0.01
Total HAPs	0.01	0.01

132. The permittee shall not exceed a throughput of 24,300,000 gallons of lube oil at SN-45 per rolling 12 month period. [Rule 19.705, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

133. The permittee shall maintain monthly records to demonstrate compliance with Specific Condition #132. The permittee shall update these records by the thirtieth day of the month following the month to which the records pertain. The twelve month rolling totals and each individual month's data shall be maintained on-site, made available to Department personnel upon request, and submitted in accordance with General Provision #7. [Rule 19.705 and 40 C.F.R. § 52 Subpart E]

SN-46
Haul Roads

Source Description

MOP has various types of trucks that travel throughout the plant to deliver raw materials to include refinery/packaging additives and paraffinic crude oil from Miller's Bluff as well as trucks that travel throughout the plant to ship out various types of bulk and packaged products. Fugitive particulate emissions result from the vehicle traffic.

Specific Conditions

134. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by compliance with Specific Condition #136 and #137. [Rule 19.501 *et seq.* and 40 C.F.R. § 52 Subpart E]

Pollutant	lb/hr	tpy
PM_{10}	3.4	3.9

135. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by compliance with Specific Condition #136 and #137. [Rule 18.801 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

Pollutant	lb/hr	tpy
PM	16.9	17.8

136. Nothing in this permit shall be construed to authorize a violation of the Arkansas Water and Air Pollution Control Act or the federal National Pollutant Discharge Elimination System (NPDES). [Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

137. The permittee shall not operate in a manner such that emissions from the Haul Roads would cause a nuisance off-site. Under normal conditions, off-site opacity less than or equal to 5% shall not be considered a nuisance. [Rule 18.501 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

SN-47
Surplus Loading/Unloading Rack

Source Description

The surplus loading/unloading rack (SN-47), designated S-60 by the facility, is used to load intermediate products of the crude unit from tanks (SN-27h) into trucks.

Specific Conditions

138. The permittee shall not exceed the emission rates set forth in the following table. Hourly emissions are based on pump equipment maximum. The permittee shall demonstrate compliance with annual emissions by compliance with Specific Condition #140. [Rule 19.501 *et seq.* and 40 C.F.R. § 52 Subpart E]

Pollutant	lb/hr	tpy
VOC	0.1	0.2

139. The permittee shall not exceed the emission rates set forth in the following table. Hourly emissions are based on pump equipment maximum. The permittee shall demonstrate compliance with annual emissions by compliance with Specific Condition #140. [Rule 18.801 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

Pollutant	lb/hr	tpy
Benzene	0.02	0.06
Total HAPs	0.05	0.20

140. The permittee shall not exceed a throughput of 49,932,000 gallons of miscellaneous intermediate products at SN-47 per rolling 12 month period. [Rule 19.705, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

141. The permittee shall maintain monthly records to demonstrate compliance with Specific Condition #140. The permittee shall update these records by the thirtieth day of the month following the month to which the records pertain. The twelve month rolling totals and each individual month's data shall be maintained on-site, made available to Department personnel upon request, and submitted in accordance with General Provision #7. [Rule 19.705 and 40 C.F.R. § 52 Subpart E]

SECTION V: COMPLIANCE PLAN AND SCHEDULE

Martin Operating Partnership L.P. will continue to operate in compliance with those identified regulatory provisions. The facility will examine and analyze future rules and regulations that may apply and determine their applicability with any necessary action taken on a timely basis.

SECTION VI: PLANTWIDE CONDITIONS

1. The permittee shall notify the Director in writing within thirty (30) days after commencing construction, completing construction, first placing the equipment and/or facility in operation, and reaching the equipment and/or facility target production rate. [Rule 19.704, 40 C.F.R. § 52 Subpart E, and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

2. If the permittee fails to start construction within eighteen months or suspends construction for eighteen months or more, the Director may cancel all or part of this permit. [Rule 19.410(B) and 40 C.F.R. § 52 Subpart E]

3. The permittee must test any equipment scheduled for testing, unless otherwise stated in the Specific Conditions of this permit or by any federally regulated requirements, within the following time frames: (1) new equipment or newly modified equipment within sixty (60) days of achieving the maximum production rate, but no later than 180 days after initial start up of the permitted source or (2) operating equipment according to the time frames set forth by the Division of Environmental Quality or within 180 days of permit issuance if no date is specified. The permittee must notify the Division of Environmental Quality of the scheduled date of compliance testing at least fifteen (15) business days in advance of such test. The permittee shall submit the compliance test results to the Division of Environmental Quality within sixty (60) calendar days after completing the testing. [Rule 19.702 and/or Rule 18.1002 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

4. The permittee must provide:

    a. Sampling ports adequate for applicable test methods;
    b. Safe sampling platforms;
    c. Safe access to sampling platforms; and
    d. Utilities for sampling and testing equipment.

    [Rule 19.702 and/or Rule 18.1002 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

5. The permittee must operate the equipment, control apparatus and emission monitoring equipment within the design limitations. The permittee shall maintain the equipment in good condition at all times. [Rule 19.303 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

6. This permit subsumes and incorporates all previously issued air permits for this facility. [Rule 26 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

7. Unless otherwise specified in the permit, approval to construct any new major stationary source or a major modification subject to 40 C.F.R. § 52.21 shall become invalid if construction is not commenced within 18 months after receipt of such approval, if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. The Division of Environmental Quality may extend the 18-month period upon a satisfactory showing that an extension is justified. [Rule 19.901 *et seq.* and 40 C.F.R. § 52 Subpart E]

8. The permittee shall not exceed a throughput of 7,700 bbl/day of crude oil at the facility per rolling 12 month period. [Rule 19.705, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

9. The permittee shall maintain monthly records to demonstrate compliance with Plantwide Condition #8. The permittee shall update these records by the thirtieth day of the month following the month to which the records pertain. The twelve month rolling totals and each individual month's data shall be maintained on-site, made available to Department personnel upon request, and submitted in accordance with General Provision #7. [Rule 19.705 and 40 C.F.R. § 52 Subpart E]

10. The naphtha loading rack emissions shall be routed to Tanks #130, #131, and #132. The naphtha storage tanks (Tanks #130, #131, and #132) shall not vent to the atmosphere. [Reg.18.1004 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

11. The heavy condensate loading rack emissions shall be routed to Tank #133. The heavy condensate storage tank (Tanks #133) shall not vent to the atmosphere. [Rule 19.705, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

12. The permittee shall not exceed the following vapor pressure limits for the materials stored at this facility. The permittee shall maintain documentation to demonstrate compliance with this specific condition. [Rule 19.705, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

Material	Average True Vapor Pressure
Additives (that contain VOC)	0.009 psi @ 70° F
Asphalt	0.0098 psi @ 302° F
Crude Oil	0.1802 psi @ 77° F
Distillate (not heavy condensate)	0.0111 psi @ 77° F
Gasoline	9 RVP
Lube Oil	0.0021 psi @ 77° F

13. The permittee shall maintain the tank number easily visible at each storage tank (each tank at SN-27a-l, SN-28, and SN-29). The permittee shall maintain a cross reference tank inventory of all storage tanks that identifies the tank number, size, installation date, and contents of the tank. [Rule 19.705, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

NSPS Subpart Ja Conditions for Flare (SN-40)

14. The permittee shall determine the total reduce sulfur concentration for each gas line directed to the affected flare. The permittee shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration of total reduced sulfur in gas discharged to the flare. [Rule 19.304 and 40 C.F.R. §§ 60.103a(a) and 60.107a(e)(1)(i-iii)]

   a. The permittee shall install operate and maintain each total reduced sulfur monitor according to Performance Specification 5 of Appendix B to Part 60.
   b. The permittee shall conduct performance evaluations of each total reduced sulfur monitor according to the requirements of §60.13(c) and Performance Specification 5 of Appendix b to Part 60. For flares that routinely have flow, the permittee of each total reduced sulfur monitor shall use EPA Method 15A of Appendix A-5 to Part 60 for conducting the relative accuracy evaluations.
   c. The permittee shall comply with the applicable quality assurance procedures in Appendix F to Part 60 for each total reduced sulfur monitor.

15. The permittee shall install, calibrate, operate and maintain a CPMS to measure and record the flow rate of the gas discharged to the flare. If a flow monitor is not already in place, the permittee shall comply with §60.107a(f) by no later than November 15, 2015, or upon startup of the flare, whichever is later. The permittee shall install, calibrate, operate and maintain each flow monitor according to the manufacturer's procedures and specifications and the following requirements [Rule 19.304 and 40 C.F.R. §§ 60.103a(a) and 60.107a(f)(1)(i-v)]:

   a. Locate the monitor in a position that provides a representative measurement of the total gas flow rate.
   b. Use a flow sensor with a measurement sensitivity of no more than 5 percent of the flow rate or 10 cubic feet per minute, whichever is greater.
   c. Use a flow monitor that is maintainable online, is able to continuously correct for temperature and pressure and is able to record flow in standard conditions (as defined in §60.2) over one-minute averages.
   d. At least quarterly, perform a visual inspection of all components of the monitor for physical and operational integrity and all electrical connections for oxidation and galvanic corrosion of the flow monitor is not equipped with a redundant flow sensor.

e. Recalibrate the flow monitor in accordance with the manufacturers' procedures and specification biennially (every two years) or at the frequency specified by the manufacturer.

16. The permittee shall develop and implement a written flare management plan in accordance with §60.103a(a)(1) through (6) no later than the date the flare becomes an affected flare. The permittee shall maintain a copy of the flare management plan on site and made available to the Department upon request. [Rule 19.304 and 40 C.F.R. §§ 60.103a(a) and 60.108a(c)(1)]

17. The permittee shall maintain records that the SN-40 pilot gas is exempt per §60.107a(a)(3)(i). [Rule 19.304 and 40 C.F.R. §§ 60.103a(a) and 60.108a(c)(5)]

18. The permittee periodically update the flare management plan to account for changes in the operation of the flare, such as new connections to the flare or the installation of a flare gas recovery system, but the plan need be re-submitted to the Administrator only if the owner or operator adds an alternative baseline flow rate, revises an existing baseline as described in paragraph (a)(4) of this section, installs a flare gas recovery system or is required to change flare designations and monitoring methods as described in §60.107a(g). The owner or operator must comply with the updated plan as submitted. [Rule 19.304 and 40 C.F.R. § 60.103a(b)(2)]

19. All versions of the plan submitted to the Administrator shall also be submitted to the following address: U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Sector Policies and Programs Division, U.S. EPA Mailroom (E143-01), Attention: Refinery Sector Lead, 109 T.W. Alexander Drive, Research Triangle Park, NC 27711. Electronic copies in lieu of hard copies may also be submitted to *refinerynsps@epa.gov*. [Rule 19.304 and 40 C.F.R. § 60.103a(b)(3)]

20. The permittee shall conduct a root cause analysis of any emission limit exceedance or process start-up, shutdown, upset, or malfunction that causes a discharge to the atmosphere in excess of 500 lb/day of SO_2; or any discharge to the flare in excess of 500,000 standard cubic feet (scf) above the baseline, determined in §60.103a(a)(4), in any 24-hour period. The permittee shall record the identification of the affected facility, the date and duration of the discharge, the results and the action taken as a result of the root cause analysis. The permittee shall maintain a copy of each root cause analysis of a discharge onsite and made available to the Department upon request. [Rule 19.304 and 40 C.F.R. §§ 60.103a(d) and 60.108a(c)(6)(ix)]

21. The permittee shall record and maintain records of discharges greater than 500 lb/day SO_2 and discharges to an affected flare in excess of 500,000 scfd. The records shall include all items listed in §60.108a(c)(6)(i) through (xi), as applicable. [Rule 19.304 and 40 C.F.R. § 60.108a(c)(6)]

22. No fuel gas that contains H_2S in excess of 162 ppmv determined hourly on a 3-hour rolling average basis shall be combusted in SN-40, except for process upset gases or fuel gas that is released to the flare as a result of relief valve leakage or other emergency malfunctions. [Rule 19.304 and 40 C.F.R. § 60.103a(h)]

NSPS Subpart Ja Conditions for Fuel Combustion Devices (SN-02 and SN-12) and Flare (SN-40)

23. The permittee shall conduct a performance test to demonstrate initial compliance with the applicable emissions limits in §60.102a and H_2S concentration requirement §60.103a(h) according to the requirements of §60.8. The notification requirements of §60.8d apply to the initial performance test. The permittee shall use the test methods in 40 CFR Part 60 Appendices A-1 through A-8. [Rule 19.304 and 40 C.F.R. § 60.104a(a), (c)]

24. A root cause analysis and a corrective action analysis required by Plantwide Condition #20 and #34 must be completed as soon as possible, but no later than 45 days. Special circumstances are outlined in §60.103a(d)(1), (2), and (5). [Rule 19.304 and 40 C.F.R. § 60.103a(d)(1-5)]

25. All corrective action(s) must be implemented within 45 days of the discharge for which the root cause and corrective action analyses were required or as soon thereafter as practicable. If an owner or operator concludes that corrective action should not be conducted, the owner or operator shall record and explain the basis for that conclusion no later than 45 days following the discharge. [Rule 19.304 and 40 C.F.R. § 60.103a(e)(1)]

26. For corrective actions that cannot be fully implemented within 45 days following the discharge for which the root cause and corrective action analyses were required, the owner or operator shall develop an implementation schedule to complete the corrective action(s) as soon as practicable. [Rule 19.304 and 40 C.F.R. § 60.103a(e)(2)]

27. No later than 45 days following the discharge for which a root cause and corrective action analyses were required, the owner or operator shall record the corrective action(s) completed to date, and, for action(s) not already completed, a schedule for implementation, including proposed commencement and completion dates. [Rule 19.304 and 40 C.F.R. § 60.103a(e)(3)]

28. The permittee shall install, operate, calibrate and maintain an instrument for continuously monitoring and recording the concentration by volume (dry basis) of H_2S in the fuel gases before being burned in any fuel gas combustion device or flare. Unless the permittee elects to comply with the flare H_2S concentration requirement by measuring TRS allowed within §60.107a(a)(2)(v) [Rule 19.304 and 40 C.F.R. § 60.107a(a)(2)]

29. For the purpose of reports required by §60.7(c), periods of excess emissions for fuel gas combustion devices subject to the emissions limitations in §60.102a(g) and flares subject to the concentration requirement in §60.103a(h) are defined as specified in paragraphs (i)(1) through (5) of this section. Determine a rolling 3-hour or a rolling daily average as the arithmetic average of the applicable 1-hour averages (e.g., a rolling 3-hour average is the arithmetic average of three contiguous 1-hour averages). Determine a rolling 30-day or a rolling 365-day average as the arithmetic average of the applicable daily averages (e.g., a rolling 30-day average is the arithmetic average of 30 contiguous daily averages). [Rule 19.304 and 40 C.F.R. §§ 60.107a(i)(1) and 60.107a(i)(2)(i)]

   a. For the fuel gas combustion devices (SN-02 and SN-12), each rolling 3-hour period during which the average concentration of H_2S as measured by the H_2S continuous monitoring system required under paragraph (a)(2) of this section exceeds 162 ppmv and each rolling 365-day period during which the average concentration as measured by the H_2S continuous monitoring system under paragraph (a)(2) of this section exceeds 60 ppmv.
   b. For the Flare (SN-40), each rolling 3-hour period during which the average concentration of H_2S as measured by the H_2S continuous monitoring system required under paragraph (a)(2) of this section exceeds 162 ppmv.

30. The permittee shall submit an excess emissions report for all periods of excess emissions according to the requirements of §60.7(c) except that the report shall contain the information specified in §60.108a(d)(1) through (7). The excess emissions report shall be submitted in accordance with General Provision No. 7. [Rule 19.304 and 40 C.F.R. § 60.108a(d)]

NSPS Subpart Ja Conditions for Fuel Gas Combustion Devices (SN-02 and SN-12)

31. The permittee shall conduct a root cause analysis and a correction action analysis after each exceedance of an applicable short-term emissions limit of 162 ppmv determined hourly on a 3-hour rolling average basis in §60.102a(g)(1) if the SO_2 discharge to the atmosphere is (500 lb) greater than the amount that would have been emitted if the emissions limits had been met during one or more consecutive periods of excess emissions or any 24-hour period, whichever is shorter. [Rule 19.304 and 40 C.F.R. § 60.103a(c)(2)]

32. Within 45 days following the end of a discharge, maintain records of discharges which exceed 500 lb of SO_2 greater than the amount that would have been emitted if the emissions limits had been met for SN-02 and SN-12. The records shall include all items listed in §60.108a(c)(6)(i) through (xi), as applicable. [Rule 19.304 and 40 C.F.R. § 60.108a(c)(6)]

33. The permittee shall not burn in any fuel that contains H_2S in excess of 162 ppmv determined hourly on a 3-hour rolling average basis and H_2S in excess of 60 ppmv determined daily on a 365 successive calendar day rolling average. The permittee shall comply with the notification, recordkeeping, and reporting requirements in §60.7. [Rule 19.304 and 40 C.F.R. §§ 60.102a(g)(1)(ii) and 60.108a(a)]

34. The permittee shall determine compliance with the H_2S emissions limit in §60.102a(g), in accordance with §60.104a(j). [Rule 19.304 and 40 C.F.R. § 60.104a(j)]

    a. The permittee shall install, operate, and maintain each H_2S monitor according to Performance Specification 7 of Appendix B to Part 60. The span value for this instrument is 300 ppmv H_2S.
    b. The permittee shall conduct performance evaluations for each H_2S monitor according to the requirements of §60.13(c) and Performance Specification 7 of Appendix B to Part 60.
    c. The permittee shall comply with the applicable quality assurance procedures in Appendix F to Part 60 for each H_2S monitor.
    d. Fuel gas combustion device having a common source of fuel gas may be monitored at only one location, if monitoring at this location accurately represents the concentration of H_2S in the fuel gas being burned.

35. The permittee shall comply with the notification, recordkeeping, and reporting requirements in §60.7, and shall Notify the Administrator of the specific monitoring provisions of 60.107a with which the facility intends to comply. Submit with the notification of initial startup required by 60.7(a)(3). [Rule 19.304 and 40 C.F.R. § 60.108a(a&b)]

NESHAP FF Conditions

36. The facility is an affected source according to 40 CFR Part 61, Subpart FF (Appendix I) – *National Emission Standard for Benzene Waste Operations*. [Rule 19.304 and 40 C.F.R. § 61 Subpart FF]

    a. The owner and operator shall determine the total annual benzene quantity from facility waste by the procedures outlined in §61.355(a). [Rule 19.304 and 40 C.F.R. § 61.355]
    b. The facility shall comply with all record keeping requirements outlined in §61.356 (b). [Rule 19.304 and 40 C.F.R. § 61.355(a)]
    c. The facility shall submit reports to the Department by following the procedures of §61.357 (a) (1)-(4). In cases where the total annual benzene quantity is less than 1 Mg/yr [as determined in Plantwide Condition #36a.], reports will comply with §61.357 (b). In cases where the total annual benzene quantity is greater than 1 Mg/yr but less than 10 Mg/yr, reports will comply with §61.357 (c). And when the total annual benzene quantity is greater than 10 Mg/yr, reports will comply with §61.357 (d). [Rule 19.304 and 40 C.F.R. § 61.357]

NSPS Subpart QQQ

37. The wastewater oil-water separators (SN-24) are subject to 40 CFR Part 60, Subpart QQQ —Standards of Performance for VOC Emissions From Petroleum Refinery Wastewater Systems. The permittee shall comply with all applicable provisions of 40 CFR Part 60, Subpart QQQ which includes, but is not limited to Plantwide Condition #38 through #52. [Rule 19.304 and 40 C.F.R. § 60 Subpart QQQ]

38. The permittee shall comply with the requirements of Plantwide Conditions #39 through #52 except during periods of startup, shutdown, or malfunction. [Rule 19.304 and 40 C.F.R. § 60.692-1(a)]

39. The permittee shall demonstrate compliance with the following exclusions through compliance with Plantwide Conditions #48, #49, and #50. [Rule 19.304 and 40 C.F.R. § 60.690]

    a. Storm water sewer systems are not subject to the requirements of this subpart.
    b. Ancillary equipment, which is physically separate from the wastewater system and does not come in contact with or store oily wastewater, is not subject to the requirements of this subpart.
    c. Non-contact cooling water systems are not subject to the requirements of this subpart.

40. The permittee shall ensure that the oil-water separators subject to this subpart meet the following requirements: [Rule 19.304 and 40 C.F.R. § 60.692-3]

    a. Each oil-water separator tank, slop oil tank, storage vessel, or other auxiliary equipment subject to the requirements of this subpart shall be equipped and operated with a fixed roof, which meets the following specifications, except as provided in paragraph (d) of this section or in § 60.693-2.
    b. The fixed roof shall be installed to completely cover the separator tank, slop oil tank, storage vessel, or other auxiliary equipment with no separation between the roof and the wall.
    c. The vapor space under a fixed roof shall not be purged unless the vapor is directed to a control device.
    d. If the roof has access doors or openings, such doors or openings shall be gasketed, latched, and kept closed at all times during operation of the separator system, except during inspection and maintenance.
    e. Roof seals, access doors, and other openings shall be checked by visual inspection initially and semiannually thereafter to ensure that no cracks or gaps occur between the roof and wall and that access doors and other openings are closed and gasketed properly.

f. When a broken seal or gasket or other problem is identified, first efforts at repair shall be made as soon as practicable, but not later than 15 calendar days after it is identified, except as provided in § 60.692-6.
g. Slop oil from an oil-water separator tank and oily wastewater from slop oil handling equipment shall be collected, stored, transported, recycled, reused, or disposed of in an enclosed system. Once slop oil is returned to the process unit or is disposed of, it is no longer within the scope of this subpart. Equipment used in handling slop oil shall be equipped with a fixed roof meeting the requirements of paragraph (a) of this condition.
h. Each oil-water separator tank, slop oil tank, storage vessel, or other auxiliary equipment that is required to comply with paragraph (a) of this condition, and not paragraph (b) of this condition, may be equipped with a pressure control valve as necessary for proper system operation. The pressure control valve shall be set at the maximum pressure necessary for proper system operation, but such that the value will not vent continuously.

41. The permittee may delay the repair required by this subpart if the repair is technically impossible without a complete or partial refinery or process unit shutdown. Repair of such equipment shall occur before the end of the next refinery or process unit shutdown. [Rule 19.304 and 40 C.F.R. § 60.692-6]

42. Installation of equipment necessary to comply with the provisions of this subpart shall occur no later than the next scheduled refinery or process unit shutdown. [Rule 19.304 and 40 C.F.R. § 60.692-7]

43. The permittee shall inspect equipment subject to Subpart QQQ for indications of potential emissions, defects, or other problems that may cause the requirements of this subpart not to be met before the applicable equipment is used. Points of inspection shall include, but are not limited to, seals, flanges, joints, gaskets, hatches, caps, and plugs. [Rule 19.304 and 40 C.F.R. § 60.696(a)]

44. The permittee shall maintain records required for compliance of this subpart for a minimum of 2 years after being recorded unless otherwise noted. [Rule 19.304 and 40 C.F.R. § 60.697(a)]

45. The permittee shall maintain records of inspections for the oil-water separators specified in Plantwide Condition #40. These records shall include the inspection location, date, and any corrective action required when a problem is identified that could result in VOC emissions. [Rule 19.304 and 40 C.F.R. § 60.697(c)]

46. If an emission point cannot be repaired or corrected without a process unit shutdown as specified in Plantwide Condition #41, the permittee shall maintain a record containing the following information: [Rule 19.304 and 40 C.F.R. § 60.697(e)]

a. The expected date of a successful repair

b. The reason for the delay
c. The signature of the owner or operator (or designee) whose decision it was that repair could not be effected without refinery or process shutdown
d. The date of successful repair or corrective action

47. The permittee shall maintain a copy of the design specifications for all equipment used to comply with the provisions of this subpart for the life of the source in a readily accessible location. These design specifications must contain the following information: [Rule 19.304 and 40 C.F.R. § 60.697(f)(1-2)]

a. Detailed schematics, and piping and instrumentation diagrams
b. The dates and descriptions of any changes in the design specifications

48. The permittee shall maintain for the life of the facility in a readily accessible location, plans or specifications which demonstrate that no wastewater from any process units or equipment is directly discharged to any applicable stormwater sewer system. [Rule 19.304 and 40 C.F.R. § 60.697(h)]

49. The permittee shall maintain for the life of the facility in a readily accessible location, plans or specifications which demonstrate that any applicable ancillary equipment does not come in contact with or store oily wastewater. [Rule 19.304 and 40 C.F.R. § 60.697(i)]

50. The permittee shall maintain for the life of the facility in a readily accessible location, plans or specifications which demonstrate that the applicable cooling water does not contact hydrocarbons or oily wastewater and is not recirculated through a cooling tower. [Rule 19.304 and 40 C.F.R. § 60.697(j)]

51. The permittee shall submit to the Administrator within 60 days after initial startup a certification that the equipment necessary to comply with these standards has been installed and that the required initial inspections or tests of process drains, sewer lines, junction boxes, oil-water separators, and closed vent systems and control devices have been carried out in accordance with these standards. Thereafter, the owner or operator shall submit to the Administrator semiannually a certification that all of the required inspections have been carried out in accordance with these standards. [Rule 19.304 and 40 C.F.R. § 60.698(b)]

52. The permittee shall submit an initial and semiannual report to the Department that summarizes all inspections when a water seal was dry or otherwise breached, when a drain cap or plug was missing or improperly installed, or when cracks, gaps, or other problems were identified that could result in VOC emissions, including information about the repairs or corrective action taken. The initial and semiannual report shall be submitted in accordance with General Provision No. 7. [Rule 19.304 and 40 C.F.R. § 60.698(c)]

53. If compliance with the provisions of this subpart is delayed pursuant to Plantwide Condition #32, the notification required under 40 CFR 60.7(a)(4) shall include the estimated date of the next scheduled refinery or process unit shutdown after the date of notification and the reason why compliance with the standards is technically impossible without a refinery or process unit shutdown. [Rule 19.304 and 40 C.F.R. § 60.698(e)]

Title VI Provisions

54. The permittee must comply with the standards for labeling of products using ozone-depleting substances. [40 C.F.R. § 82 Subpart E]

    a. All containers containing a class I or class II substance stored or transported, all products containing a class I substance, and all products directly manufactured with a class I substance must bear the required warning statement if it is being introduced to interstate commerce pursuant to § 82.106.
    b. The placement of the required warning statement must comply with the requirements pursuant to § 82.108.
    c. The form of the label bearing the required warning must comply with the requirements pursuant to § 82.110.
    d. No person may modify, remove, or interfere with the required warning statement except as described in § 82.112.

55. The permittee must comply with the standards for recycling and emissions reduction, except as provided for MVACs in Subpart B. [40 C.F.R. § 82 Subpart F]

    a. Persons opening appliances for maintenance, service, repair, or disposal must comply with the required practices pursuant to § 82.156.
    b. Equipment used during the maintenance, service, repair, or disposal of appliances must comply with the standards for recycling and recovery equipment pursuant to § 82.158.
    c. Persons performing maintenance, service repair, or disposal of appliances must be certified by an approved technician certification program pursuant to § 82.161.
    d. Persons disposing of small appliances, MVACs, and MVAC like appliances must comply with record keeping requirements pursuant to § 82.166. ("MVAC like appliance" as defined at § 82.152)
    e. Persons owning commercial or industrial process refrigeration equipment must comply with leak repair requirements pursuant to § 82.156.
    f. Owners/operators of appliances normally containing 50 or more pounds of refrigerant must keep records of refrigerant purchased and added to such appliances pursuant to § 82.166.

56. If the permittee manufactures, transforms, destroys, imports, or exports a class I or class II substance, the permittee is subject to all requirements as specified in 40 C.F.R. § 82 Subpart A, Production and Consumption Controls.

57. If the permittee performs a service on motor (fleet) vehicles when this service involves ozone depleting substance refrigerant (or regulated substitute substance) in the motor vehicle air conditioner (MVAC), the permittee is subject to all the applicable requirements as specified in 40 C.F.R. § 82 Subpart B, Servicing of Motor Vehicle Air Conditioners.

    The term "motor vehicle" as used in Subpart B does not include a vehicle in which final assembly of the vehicle has not been completed. The term "MVAC" as used in Subpart B does not include the air tight sealed refrigeration system used as refrigerated cargo, or the system used on passenger buses using HCFC 22 refrigerant.

58. The permittee can switch from any ozone depleting substance to any alternative listed in the Significant New Alternatives Program (SNAP) promulgated pursuant to 40 C.F.R. § 82 Subpart G.

Permit Shield

59. Compliance with the conditions of this permit shall be deemed compliance with all applicable requirements, as of the date of permit issuance, included in and specifically identified in the following table of this condition. The permit specifically identifies the following as applicable requirements based upon the information submitted by the permittee in an application dated September 1, 2023.

Applicable Regulations

Source No.	**Regulation**	**Description**
Facility	Rule 18	Arkansas Air Pollution Control Code
Facility	Rule 19	Rules of the Arkansas Plan of Implementation for Air Pollution Control
Facility	Rule 26	Rules of the Arkansas Operating Air Permit Program
Facility	40 CFR Part 52	Approval and Promulgation of Implementation Plans
SN-12	40 CFR Part 60 Subpart J	Standards of Performance for Petroleum Refineries
SN-02 and SN-40	40 CFR Part 60 Subpart Ja	Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007
SN-27c: Tank 100, Tank 228	40 CFR Part 60 Subpart UU	Standards of Performance for Asphalt Processing and Asphalt Roofing Manufacture

Source No.	Regulation	Description
SN-24	40 CFR Part 60 Subpart QQQ	Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems
SN-41, SN-43, and SN-48	40 CFR Part 60 Subpart IIII	Standards of Performance for Stationary Compression Ignition Internal Combustion Engines
Facility	40 CFR Part 61 Subpart FF	National Emission Standard for Benzene Waste Operations
SN-27g	40 CFR Part 63 Subpart CCCCCC	National Emission Standards for Hazardous Air Pollutants for Source Category: Gasoline Dispensing Facilities
SN-41, SN-42, SN-43, and SN-48	40 CFR Part 63 Subpart ZZZZ	National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines
SN-40	40 CFR Part 64	Compliance Assurance Monitoring

The permit specifically identifies the following as inapplicable based upon information submitted by the permittee in an application dated September 1, 2023.

Inapplicable Regulations

Source No.	Regulation	Description
SN-01, SN-02, SN-03, SN-08, SN-12, SN-26, SN-30	40 CFR Part 60 Subpart D	Standards of Performance for Fossil-Fuel-Fired Steam Generators
	40 CFR Part 60 Subpart Da	Standards of Performance for Electric Utility Steam Generating Units
	40 CFR Part 60 Subpart Db	Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units
	40 CFR Part 60 Subpart Dc	Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units
SN-27a – SN-27l, SN-28, SN-29	40 CFR Part 60 Subpart K	Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978
	40 CFR Part 60 Subpart Ka	Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984

Source No.	Regulation	Description
	40 CFR Part 60 Subpart Kb	Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984
Facility	40 CFR Part 60 Subpart GGG	Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After January 4, 1983, and on or Before November 7, 2006
Facility	40 CFR Part 60 Subpart GGGa	Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006
Facility	40 CFR Part 63 Subpart CC	National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries
Facility	40 CFR Part 63 Subpart UUU	National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units
SN-26	40 CFR Part 63 Subpart DDDDD	National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters
SN-26	40 CFR Part 63 Subpart JJJJJJ	National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources

SECTION VII: INSIGNIFICANT ACTIVITIES

The Division of Environmental Quality deems the following types of activities or emissions as insignificant on the basis of size, emission rate, production rate, or activity in accordance with Group A of the Insignificant Activities list found in Rule 18 and Rule 19 Appendix A. Group B insignificant activities may be listed but are not required to be listed in permits. Insignificant activity emission determinations rely upon the information submitted by the permittee in an application dated September 1, 2023. [Rule 26.304 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

Description	Category
4,500 gal Diesel Tank for SN-48	A-3
Decant Tanks 1 through 4 (7,644 gallons each)	A-3
Tank #312 (Caustic)	A-4
Tank #313 (NaHS)	A-4
Tank #314 (NaHS)	A-4
Tank #400 (Caustic)	A-4
Tank #402 (Caustic)	A-4
Lab Equipment	A-5
Asphalt Tank Heater (at Tank 100)	A-13
Miller’s Bluff Crude Oil Truck Loading	A-13
210,000 gal Sour Water Stripper Surge Tank	A-13
Packaging Plant – Plastic Extrusion	A-13
Packaging Plant – Six Plastic Silos	A-13
Lube Oil Packaging Plant Operations	A-13
Cooling Tower No. 1	A-13
Cooling Tower No. 2	A-13

SECTION VIII: GENERAL PROVISIONS

1. Any terms or conditions included in this permit which specify and reference Arkansas Pollution Control & Ecology Commission Rule 18 or the Arkansas Water and Air Pollution Control Act (Ark. Code Ann. § 8-4-101 *et seq.*) as the sole origin of and authority for the terms or conditions are not required under the Clean Air Act or any of its applicable requirements, and are not federally enforceable under the Clean Air Act. Arkansas Pollution Control & Ecology Commission Rule 18 was adopted pursuant to the Arkansas Water and Air Pollution Control Act (Ark. Code Ann. § 8-4-101 *et seq.*). Any terms or conditions included in this permit which specify and reference Arkansas Pollution Control & Ecology Commission Rule 18 or the Arkansas Water and Air Pollution Control Act (Ark. Code Ann. § 8-4-101 *et seq.*) as the origin of and authority for the terms or conditions are enforceable under this Arkansas statute. [40 C.F.R. § 70.6(b)(2)]

2. This permit shall be valid for a period of five (5) years beginning on the date this permit becomes effective and ending five (5) years later. [40 C.F.R. § 70.6(a)(2) and Rule 26.701(B)]

3. The permittee must submit a complete application for permit renewal at least six (6) months before permit expiration. Permit expiration terminates the permittee's right to operate unless the permittee submitted a complete renewal application at least six (6) months before permit expiration. If the permittee submits a complete application, the existing permit will remain in effect until the Division of Environmental Quality takes final action on the renewal application. The Division of Environmental Quality will not necessarily notify the permittee when the permit renewal application is due. [Rule 26.406]

4. Where an applicable requirement of the Clean Air Act, as amended, 42 U.S.C. 7401, *et seq.* (Act) is more stringent than an applicable requirement of regulations promulgated under Title IV of the Act, the permit incorporates both provisions into the permit, and the Director or the Administrator can enforce both provisions. [40 C.F.R. § 70.6(a)(1)(ii) and Rule 26.701(A)(2)]

5. The permittee must maintain the following records of monitoring information as required by this permit.

    a. The date, place as defined in this permit, and time of sampling or measurements;
    b. The date(s) analyses performed;
    c. The company or entity performing the analyses;
    d. The analytical techniques or methods used;
    e. The results of such analyses; and
    f. The operating conditions existing at the time of sampling or measurement.

    [40 C.F.R. § 70.6(a)(3)(ii)(A) and Rule 26.701(C)(2)]

6. The permittee must retain the records of all required monitoring data and support information for at least five (5) years from the date of the monitoring sample, measurement, report, or application. Support information includes all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit. [40 C.F.R. § 70.6(a)(3)(ii)(B) and Rule 26.701(C)(2)(b)]

7. The permittee must submit reports of all required monitoring every six (6) months. If the permit establishes no other reporting period, the reporting period shall end on the last day of the month six months after the issuance of the initial Title V permit and every six months thereafter. The report is due on the first day of the second month after the end of the reporting period. The first report due after issuance of the initial Title V permit shall contain six months of data and each report thereafter shall contain 12 months of data. The report shall contain data for all monitoring requirements in effect during the reporting period. If a monitoring requirement is not in effect for the entire reporting period, only those months of data in which the monitoring requirement was in effect are required to be reported. The report must clearly identify all instances of deviations from permit requirements. A responsible official as defined in Rule 26.2 must certify all required reports. The permittee will send the reports electronically using https://eportal.adeq.state.ar.us or mail them to the address below:

   Division of Environmental Quality
   Office of Air Quality
   ATTN: Compliance Inspector Supervisor
   5301 Northshore Drive
   North Little Rock, AR 72118-5317

   [40 C.F.R. § 70.6(a)(3)(iii)(A) and Rule 26.701(C)(3)(a)]

8. The permittee shall report to the Division of Environmental Quality all deviations from permit requirements, including those attributable to upset conditions as defined in the permit.

   a. For all upset conditions (as defined in Rule 19.601), the permittee will make an initial report to the Division of Environmental Quality by the next business day after the discovery of the occurrence. The initial report may be made by telephone and shall include:

      i. The facility name and location;
      ii. The process unit or emission source deviating from the permit limit;
      iii. The permit limit, including the identification of pollutants, from which deviation occurs;
      iv. The date and time the deviation started;
      v. The duration of the deviation;

vi. The emissions during the deviation;
vii. The probable cause of such deviations;
viii. Any corrective actions or preventive measures taken or being taken to prevent such deviations in the future; and
ix. The name of the person submitting the report.

The permittee shall make a full report in writing to the Division of Environmental Quality within five (5) business days of discovery of the occurrence. The report must include, in addition to the information required by the initial report, a schedule of actions taken or planned to eliminate future occurrences and/or to minimize the amount the permit's limits were exceeded and to reduce the length of time the limits were exceeded. The permittee may submit a full report in writing (by facsimile, overnight courier, or other means) by the next business day after discovery of the occurrence, and the report will serve as both the initial report and full report.

b. For all deviations, the permittee shall report such events in semi-annual reporting and annual certifications required in this permit. This includes all upset conditions reported in 8a above. The semi-annual report must include all the information as required by the initial and full reports required in 8a.

[Rule 19.601, Rule 19.602, Rule 26.701(C)(3)(b), and 40 C.F.R. § 70.6(a)(3)(iii)(B)]

9. If any provision of the permit or the application thereof to any person or circumstance is held invalid, such invalidity will not affect other provisions or applications hereof which can be given effect without the invalid provision or application, and to this end, provisions of this Rule are declared to be separable and severable. [40 C.F.R. § 70.6(a)(5), Rule 26.701(E), and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

10. The permittee must comply with all conditions of this Part 70 permit. Any permit noncompliance with applicable requirements as defined in Rule 26 constitutes a violation of the Clean Air Act, as amended, 42 U.S.C. § 7401, *et seq.* and is grounds for enforcement action; for permit termination, revocation and reissuance, for permit modification; or for denial of a permit renewal application. [40 C.F.R. § 70.6(a)(6)(i) and Rule 26.701(F)(1)]

11. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity to maintain compliance with the conditions of this permit. [40 C.F.R. § 70.6(a)(6)(ii) and Rule 26.701(F)(2)]

12. The Division of Environmental Quality may modify, revoke, reopen and reissue the permit or terminate the permit for cause. The filing of a request by the permittee for a permit modification, revocation and reissuance, termination, or of a notification of planned changes or anticipated noncompliance does not stay any permit condition. [40 C.F.R. § 70.6(a)(6)(iii) and Rule 26.701(F)(3)]

13. This permit does not convey any property rights of any sort, or any exclusive privilege. [40 C.F.R. § 70.6(a)(6)(iv) and Rule 26.701(F)(4)]

14. The permittee must furnish to the Director, within the time specified by the Director, any information that the Director may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit or to determine compliance with the permit. Upon request, the permittee must also furnish to the Director copies of records required by the permit. For information the permittee claims confidentiality, the Division of Environmental Quality may require the permittee to furnish such records directly to the Director along with a claim of confidentiality. [40 C.F.R. § 70.6(a)(6)(v) and Rule 26.701(F)(5)]

15. The permittee must pay all permit fees in accordance with the procedures established in Rule 9. [40 C.F.R. § 70.6(a)(7) and Rule 26.701(G)]

16. No permit revision shall be required, under any approved economic incentives, marketable permits, emissions trading and other similar programs or processes for changes provided for elsewhere in this permit. [40 C.F.R. § 70.6(a)(8) and Rule 26.701(H)]

17. If the permit allows different operating scenarios, the permittee shall, contemporaneously with making a change from one operating scenario to another, record in a log at the permitted facility a record of the operational scenario. [40 C.F.R. § 70.6(a)(9)(i) and Rule 26.701(I)(1)]

18. The Administrator and citizens may enforce under the Act all terms and conditions in this permit, including any provisions designed to limit a source's potential to emit, unless the Division of Environmental Quality specifically designates terms and conditions of the permit as being federally unenforceable under the Act or under any of its applicable requirements. [40 C.F.R. § 70.6(b) and Rule 26.702(A) and (B)]

19. Any document (including reports) required by this permit pursuant to 40 C.F.R. § 70 must contain a certification by a responsible official as defined in Rule 26.2. [40 C.F.R. § 70.6(c)(1) and Rule 26.703(A)]

20. The permittee must allow an authorized representative of the Division of Environmental Quality, upon presentation of credentials, to perform the following: [40 C.F.R. § 70.6(c)(2) and Rule 26.703(B)]

    a. Enter upon the permittee's premises where the permitted source is located or emissions related activity is conducted, or where records must be kept under the conditions of this permit;
    b. Have access to and copy, at reasonable times, any records required under the conditions of this permit;

c. Inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under this permit; and
d. As authorized by the Act, sample or monitor at reasonable times substances or parameters for assuring compliance with this permit or applicable requirements.

21. The permittee shall submit a compliance certification with the terms and conditions contained in the permit, including emission limitations, standards, or work practices. The permittee must submit the compliance certification annually. If the permit establishes no other reporting period, the reporting period shall end on the last day of the anniversary month of the initial Title V permit. The report is due on the first day of the second month after the end of the reporting period. The permittee must also submit the compliance certification to the Administrator as well as to the Division of Environmental Quality. All compliance certifications required by this permit must include the following: [40 C.F.R. § 70.6(c)(5) and Rule 26.703(E)(3)]

    a. The identification of each term or condition of the permit that is the basis of the certification;
    b. The compliance status;
    c. Whether compliance was continuous or intermittent;
    d. The method(s) used for determining the compliance status of the source, currently and over the reporting period established by the monitoring requirements of this permit; and
    e. Such other facts as the Division of Environmental Quality may require elsewhere in this permit or by § 114(a)(3) and § 504(b) of the Act.

22. Nothing in this permit will alter or affect the following: [Rule 26.704(C)]

    a. The provisions of Section 303 of the Act (emergency orders), including the authority of the Administrator under that section;
    b. The liability of the permittee for any violation of applicable requirements prior to or at the time of permit issuance;
    c. The applicable requirements of the acid rain program, consistent with § 408(a) of the Act; or
    d. The ability of EPA to obtain information from a source pursuant to § 114 of the Act.

23. This permit authorizes only those pollutant emitting activities addressed in this permit. [Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

24. The permittee may request in writing and at least 15 days in advance of the deadline, an extension to any testing, compliance or other dates in this permit. No such extensions are authorized until the permittee receives written Division of Environmental Quality approval. The Division of Environmental Quality may grant such a request, at its discretion in the following circumstances:

a. Such an extension does not violate a federal requirement;
b. The permittee demonstrates the need for the extension; and
c. The permittee documents that all reasonable measures have been taken to meet the current deadline and documents reasons it cannot be met.

[Rule 18.314(A), Rule 19.416(A), Rule 26.1013(A), Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 52 Subpart E]

25. The permittee may request in writing and at least 30 days in advance, temporary emissions and/or testing that would otherwise exceed an emission rate, throughput requirement, or other limit in this permit. No such activities are authorized until the permittee receives written Division of Environmental Quality approval. Any such emissions shall be included in the facility's total emissions and reported as such. The Division of Environmental Quality may grant such a request, at its discretion under the following conditions:

a. Such a request does not violate a federal requirement;
b. Such a request is temporary in nature;
c. Such a request will not result in a condition of air pollution;
d. The request contains such information necessary for the Division of Environmental Quality to evaluate the request, including but not limited to, quantification of such emissions and the date/time such emission will occur;
e. Such a request will result in increased emissions less than five tons of any individual criteria pollutant, one ton of any single HAP and 2.5 tons of total HAPs; and
f. The permittee maintains records of the dates and results of such temporary emissions/testing.

[Rule 18.314(B), Rule 19.416(B), Rule 26.1013(B), Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 52 Subpart E]

26. The permittee may request in writing and at least 30 days in advance, an alternative to the specified monitoring in this permit. No such alternatives are authorized until the permittee receives written Division of Environmental Quality approval. The Division of Environmental Quality may grant such a request, at its discretion under the following conditions:

a. The request does not violate a federal requirement;
b. The request provides an equivalent or greater degree of actual monitoring to the current requirements; and
c. Any such request, if approved, is incorporated in the next permit modification application by the permittee.

[Rule 18.314(C), Rule 19.416(C), Rule 26.1013(C), Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 52 Subpart E]

27. Any credible evidence based on sampling, monitoring, and reporting may be used to determine violations of applicable emission limitations. [Rule 18.1001, Rule 19.701, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 52 Subpart E]

Appendix A

40 C.F.R. § 60 Subpart J—*Standards of Performance for Petroleum Refineries*

Title 40 —Protection of Environment
Chapter I —Environmental Protection Agency
Subchapter C —Air Programs
Part 60 —Standards of Performance for New Stationary Sources

Authority: 42 U.S.C. 7401 *et seq.*

Source: 36 FR 24877, Dec. 23, 1971, unless otherwise noted.

Subpart J—Standards of Performance for Petroleum Refineries

§ 60.100 Applicability, designation of affected facility, and reconstruction.

(a) The provisions of this subpart are applicable to the following affected facilities in petroleum refineries: fluid catalytic cracking unit catalyst regenerators, fuel gas combustion devices, and all Claus sulfur recovery plants except Claus plants with a design capacity for sulfur feed of 20 long tons per day (LTD) or less. The Claus sulfur recovery plant need not be physically located within the boundaries of a petroleum refinery to be an affected facility, provided it processes gases produced within a petroleum refinery.

(b) Any fluid catalytic cracking unit catalyst regenerator or fuel gas combustion device under paragraph (a) of this section other than a flare which commences construction, reconstruction or modification after June 11, 1973, and on or before May 14, 2007, or any fuel gas combustion device under paragraph (a) of this section that is also a flare which commences construction, reconstruction or modification after June 11, 1973, and on or before June 24, 2008, or any Claus sulfur recovery plant under paragraph (a) of this section which commences construction, reconstruction or modification after October 4, 1976, and on or before May 14, 2007, is subject to the requirements of this subpart except as provided under paragraphs (c) through (e) of this section.

(c) Any fluid catalytic cracking unit catalyst regenerator under paragraph (b) of this section which commences construction, reconstruction, or modification on or before January 17, 1984, is exempted from § 60.104(b).

(d) Any fluid catalytic cracking unit in which a contact material reacts with petroleum derivatives to improve feedstock quality and in which the contact material is regenerated by burning off coke and/or other deposits and that commences construction, reconstruction, or modification on or before January 17, 1984, is exempt from this subpart.

(e) Owners or operators may choose to comply with the applicable provisions of subpart Ja of this part to satisfy the requirements of this subpart for an affected facility.

(f) For purposes of this subpart, under § 60.15, the "fixed capital cost of the new components" includes the fixed capital cost of all depreciable components which are or will be replaced pursuant to all continuous programs of component replacement which are commenced within any 2-year period following January 17, 1984. For purposes of this paragraph, "commenced" means that an owner or operator has undertaken a continuous program of component replacement or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of component replacement.

[43 FR 10868, Mar. 15, 1978, as amended at 44 FR 61543, Oct. 25, 1979; 54 FR 34026, Aug. 17, 1989; 73 FR 35865, June 24, 2008; 77 FR 56463, Sep. 12, 2012]

§ 60.101 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A.

(a) ***Petroleum refinery*** means any facility engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants, or other products through distillation of petroleum or through redistillation, cracking or reforming of unfinished petroleum derivatives.

(b) ***Petroleum*** means the crude oil removed from the earth and the oils derived from tar sands, shale, and coal.

(c) ***Process gas*** means any gas generated by a petroleum refinery process unit, except fuel gas and process upset gas as defined in this section.

(d) ***Fuel gas*** means any gas which is generated at a petroleum refinery and which is combusted. Fuel gas includes natural gas when the natural gas is combined and combusted in any proportion with a gas generated at a refinery. Fuel gas does not include gases generated by catalytic cracking unit catalyst regenerators and fluid coking burners. Fuel gas does not include vapors that are collected and combusted in a thermal oxidizer or flare installed to control emissions from wastewater treatment units or marine tank vessel loading operations.

(e) ***Process upset gas*** means any gas generated by a petroleum refinery process unit as a result of start-up, shut-down, upset or malfunction.

(f) ***Refinery process unit*** means any segment of the petroleum refinery in which a specific processing operation is conducted.

(g) ***Fuel gas combustion device*** means any equipment, such as process heaters, boilers and flares used to combust fuel gas, except facilities in which gases are combusted to produce sulfur or sulfuric acid.

(h) ***Coke burn-off*** means the coke removed from the surface of the fluid catalytic cracking unit catalyst by combustion in the catalyst regenerator. The rate of coke burn-off is calculated by the formula specified in § 60.106.

(i) ***Claus sulfur recovery plant*** means a process unit which recovers sulfur from hydrogen sulfide by a vapor-phase catalytic reaction of sulfur dioxide and hydrogen sulfide.

(j) ***Oxidation control system*** means an emission control system which reduces emissions from sulfur recovery plants by converting these emissions to sulfur dioxide.

(k) ***Reduction control system*** means an emission control system which reduces emissions from sulfur recovery plants by converting these emissions to hydrogen sulfide.

(l) ***Reduced sulfur compounds*** means hydrogen sulfide (H_2S), carbonyl sulfide (COS) and carbon disulfide (CS_2).

(m) ***Fluid catalytic cracking unit*** means a refinery process unit in which petroleum derivatives are continuously charged; hydrocarbon molecules in the presence of a catalyst suspended in a fluidized bed are fractured into smaller molecules, or react with a contact material suspended in a fluidized bed to improve feedstock quality for additional processing; and the catalyst or contact material is continuously regenerated by burning off coke and other deposits. The unit includes the riser, reactor, regenerator, air blowers, spent catalyst or contact material stripper, catalyst or contact material recovery equipment, and regenerator equipment for controlling air pollutant emissions and for heat recovery.

(n) ***Fluid catalytic cracking unit catalyst regenerator*** means one or more regenerators (multiple regenerators) which comprise that portion of the fluid catalytic cracking unit in which coke burn-off and catalyst or contact material regeneration occurs, and includes the regenerator combustion air blower(s).

(o) ***Fresh feed*** means any petroleum derivative feedstock stream charged directly into the riser or reactor of a fluid catalytic cracking unit except for petroleum derivatives recycled within the fluid catalytic cracking unit, fractionator, or gas recovery unit.

(p) ***Contact material*** means any substance formulated to remove metals, sulfur, nitrogen, or any other contaminant from petroleum derivatives.

(q) ***Valid day*** means a 24-hour period in which at least 18 valid hours of data are obtained. A “valid hour” is one in which at least 2 valid data points are obtained.

[39 FR 9315, Mar. 8, 1974, as amended at 43 FR 10868, Mar. 15, 1978; 44 FR 13481, Mar. 12, 1979; 45 FR 79453, Dec. 1, 1980; 54 FR 34027, Aug. 17, 1989; 73 FR 35865, June 24, 2008; 77 FR 56463, Sep. 12, 2012]

§ 60.102 Standard for particulate matter.

Each owner or operator of any fluid catalytic cracking unit catalyst regenerator that is subject to the requirements of this subpart shall comply with the emission limitations set forth in this section on and after the date on which the initial performance test, required by § 60.8, is completed, but not later than 60 days after achieving the maximum production rate at which the fluid catalytic cracking unit catalyst regenerator will be operated, or 180 days after initial startup, whichever comes first.

(a) No owner or operator subject to the provisions of this subpart shall discharge or cause the discharge into the atmosphere from any fluid catalytic cracking unit catalyst regenerator:

(1) Particulate matter in excess of 1.0 kg/Mg (2.0 lb/ton) of coke burn-off in the catalyst regenerator.

(2) Gases exhibiting greater than 30 percent opacity, except for one six-minute average opacity reading in any one hour period.

(b) Where the gases discharged by the fluid catalytic cracking unit catalyst regenerator pass through an incinerator or waste heat boiler in which auxiliary or supplemental liquid or solid fossil fuel is burned, particulate matter in excess of that permitted by paragraph (a)(1) of this section may be emitted to the atmosphere, except that the incremental rate of particulate matter emissions shall not exceed 43 grams per Gigajoule (g/GJ) (0.10 lb/million British thermal units (Btu)) of heat input attributable to such liquid or solid fossil fuel.

[39 FR 9315, Mar. 8, 1974, as amended at 42 FR 32427, June 24, 1977; 42 FR 39389, Aug. 4, 1977; 43 FR 10868, Feb. 15, 1978; 54 FR 34027, Aug. 17, 1989; 65 FR 61753, Oct. 17, 2000; 73 FR 35866, June 24, 2008]

§ 60.103 Standard for carbon monoxide.

Each owner or operator of any fluid catalytic cracking unit catalyst regenerator that is subject to the requirements of this subpart shall comply with the emission limitations set forth in this section on and after the date on which the initial performance test, required by § 60.8, is completed, but not later than 60 days after achieving the maximum production rate at which the fluid catalytic cracking unit catalyst regenerator will be operated, or 180 days after initial startup, whichever comes first.

(a) No owner or operator subject to the provisions of this subpart shall discharge or cause the discharge into the atmosphere from any fluid catalytic cracking unit catalyst regenerator any gases that contain carbon monoxide (CO) in excess of 500 ppm by volume (dry basis).

[54 FR 34027, Aug. 17, 1989, as amended at 55 FR 40175, Oct. 2, 1990]

§ 60.104 Standards for sulfur oxides.

Each owner or operator that is subject to the requirements of this subpart shall comply with the emission limitations set forth in this section on and after the date on which the initial performance test, required by § 60.8, is completed, but not later than 60 days after achieving the maximum production rate at which the affected facility will be operated, or 180 days after initial startup, whichever comes first.

(a) No owner or operator subject to the provisions of this subpart shall:

(1) Burn in any fuel gas combustion device any fuel gas that contains hydrogen sulfide (H_2S) in excess of 230 mg/dscm (0.10 gr/dscf). The combustion in a flare of process upset gases or fuel gas that is released to the flare as a result of relief valve leakage or other emergency malfunctions is exempt from this paragraph.

(2) Discharge or cause the discharge of any gases into the atmosphere from any Claus sulfur recovery plant containing in excess of:

(i) For an oxidation control system or a reduction control system followed by incineration, 250 ppm by volume (dry basis) of sulfur dioxide (SO_2) at zero percent excess air.

(ii) For a reduction control system not followed by incineration, 300 ppm by volume of reduced sulfur compounds and 10 ppm by volume of hydrogen sulfide (H_2S), each calculated as ppm SO_2 by volume (dry basis) at zero percent excess air.

(b) Each owner or operator that is subject to the provisions of this subpart shall comply with one of the following conditions for each affected fluid catalytic cracking unit catalyst regenerator:

(1) With an add-on control device, reduce SO_2 emissions to the atmosphere by 90 percent or maintain SO_2 emissions to the atmosphere less than or equal to 50 ppm by volume (ppmv), whichever is less stringent; or

(2) Without the use of an add-on control device to reduce SO_2 emission, maintain sulfur oxides emissions calculated as SO_2 to the atmosphere less than or equal to 9.8 kg/Mg (20 lb/ton) coke burn-off; or

(3) Process in the fluid catalytic cracking unit fresh feed that has a total sulfur content no greater than 0.30 percent by weight.

(c) Compliance with paragraph (b)(1), (b)(2), or (b)(3) of this section is determined daily on a 7-day rolling average basis using the appropriate procedures outlined in § 60.106.

(d) A minimum of 22 valid days of data shall be obtained every 30 rolling successive calendar days when complying with paragraph (b)(1) of this section.

[43 FR 10869, Mar. 15, 1978, as amended at 54 FR 34027, Aug. 17, 1989; 55 FR 40175, Oct. 2, 1990; 65 FR 61754, Oct. 17, 2000; 73 FR 35866, June 24, 2008]

§ 60.105 Monitoring of emissions and operations.

(a) Continuous monitoring systems shall be installed, calibrated, maintained, and operated by the owner or operator subject to the provisions of this subpart as follows:

(1) For fluid catalytic cracking unit catalyst regenerators subject to § 60.102(a)(2), an instrument for continuously monitoring and recording the opacity of emissions into the atmosphere. The instrument shall be spanned at 60, 70, or 80 percent opacity.

(2) For fluid catalytic cracking unit catalyst regenerators subject to § 60.103(a), an instrument for continuously monitoring and recording the concentration by volume (dry basis) of CO emissions into the atmosphere, except as provided in paragraph (a)(2) (ii) of this section.

(i) The span value for this instrument is 1,000 ppm CO.

(ii) A CO continuous monitoring system need not be installed if the owner or operator demonstrates that the average CO emissions are less than 50 ppm (dry basis) and also files a written request for exemption to the Administrator and receives such an exemption. The demonstration shall consist of continuously monitoring CO emissions for 30 days using an instrument that shall meet the requirements of Performance Specification 4 of appendix B of this part. The span value shall be 100 ppm CO instead of 1,000 ppm, and the relative accuracy limit shall be 10 percent of the average CO emissions or 5 ppm CO, whichever is greater. For instruments that are identical to Method 10 and employ the sample conditioning system of Method 10A, the alternative relative accuracy test procedure in § 10.1 of Performance Specification 2 may be used in place of the relative accuracy test.

(3) For fuel gas combustion devices subject to § 60.104(a)(1), either an instrument for continuously monitoring and recording the concentration by volume (dry basis, zero percent excess air) of SO_2 emissions into the atmosphere or monitoring as provided in paragraph (a)(4) of this section). The monitor shall include an oxygen monitor for correcting the data for excess.

(i) The span values for this monitor are 50 ppm SO_2 and 25 percent oxygen (O_2).

(ii) The SO_2 monitoring level equivalent to the H_2S standard under § 60.104(a)(1) shall be 20 ppm (dry basis, zero percent excess air).

(iii) The performance evaluations for this SO_2 monitor under § 60.13(c) shall use Performance Specification 2. Methods 6 or 6C and 3 or 3A shall be used for conducting the relative accuracy evaluations. Method 6 samples shall be taken at a flow rate of approximately 2 liters/min for at least 30 minutes. The relative accuracy limit shall be 20 percent or 4 ppm, whichever is greater, and the calibration drift limit shall be 5 percent of the established span value.

(iv) Fuel gas combustion devices having a common source of fuel gas may be monitored at only one location (i.e., after one of the combustion devices), if monitoring at this location accurately represents the SO_2 emissions into the atmosphere from each of the combustion devices.

(4) Instead of the SO_2 monitor in paragraph (a)(3) of this section for fuel gas combustion devices subject to § 60.104(a)(1), an instrument for continuously monitoring and recording the concentration (dry basis) of H_2S in fuel gases before being burned in any fuel gas combustion device.

(i) The span value for this instrument is 425 mg/dscm H_2S.

(ii) Fuel gas combustion devices having a common source of fuel gas may be monitored at only one location, if monitoring at this location accurately represents the concentration of H_2S in the fuel gas being burned.

(iii) The performance evaluations for this H_2S monitor under § 60.13(c) shall use Performance Specification 7. Method 11, 15, 15A, or 16 shall be used for conducting the relative accuracy evaluations.

(iv) The owner or operator of a fuel gas combustion device is not required to comply with paragraph (a)(3) or (4) of this section for fuel gas streams that are exempt under § 60.104(a)(1) and fuel gas streams combusted in a fuel gas combustion device that are inherently low in sulfur content. Fuel gas streams meeting one of the requirements in paragraphs (a)(4)(iv)(A) through (D) of this section will be considered inherently low in sulfur content. If the composition of a fuel gas stream changes such that it is no longer exempt under § 60.104(a)(1) or it no longer meets one of the requirements in paragraphs (a)(4)(iv)(A) through (D) of this section, the owner or operator must begin continuous monitoring under paragraph (a)(3) or (4) of this section within 15 days of the change.

(A) Pilot gas for heaters and flares.

(B) Fuel gas streams that meet a commercial-grade product specification for sulfur content of 30 ppmv or less. In the case of a liquefied petroleum gas (LPG) product specification in the pressurized liquid state, the gas phase sulfur content should be evaluated assuming complete vaporization of the LPG and sulfur containing-compounds at the product specification concentration.

(C) Fuel gas streams produced in process units that are intolerant to sulfur contamination, such as fuel gas streams produced in the hydrogen plant, the catalytic reforming unit, the isomerization unit, and HF alkylation process units.

(D) Other fuel gas streams that an owner or operator demonstrates are low-sulfur according to the procedures in paragraph (b) of this section.

(5) For Claus sulfur recovery plants with oxidation control systems or reduction control systems followed by incineration subject to § 60.104(a)(2)(i), an instrument for continuously monitoring and recording the concentration (dry basis, zero percent excess air) of SO_2 emissions into the atmosphere. The monitor shall include an oxygen monitor for correcting the data for excess air.

(i) The span values for this monitor are 500 ppm SO_2 and 25 percent O_2.

(ii) The performance evaluations for this SO_2 monitor under § 60.13(c) shall use Performance Specification 2. Methods 6 or 6C and 3 or 3A shall be used for conducting the relative accuracy evaluations.

(6) For Claus sulfur recovery plants with reduction control systems not followed by incineration subject to § 60.104(a)(2)(ii), an instrument for continuously monitoring and recording the concentration of reduced sulfur and O_2 emissions into the atmosphere. The reduced sulfur emissions shall be calculated as SO_2 (dry basis, zero percent excess air).

(i) The span values for this monitor are 450 ppm reduced sulfur and 25 percent O_2.

(ii) The performance evaluations for this reduced sulfur (and O_2) monitor under § 60.13(c) shall use Performance Specification 5 of appendix B of this part(and Performance Specification 3 of appendix B of this partfor the O_2 analyzer). Methods 15 or 15A and Method 3 shall be used for conducting the relative accuracy evaluations. If Method 3 yields O_2 concentrations below 0.25 percent during the performance specification test, the O_2 concentration may be assumed to be zero and the reduced sulfur CEMS need not include an O_2 monitor.

(7) In place of the reduced sulfur monitor under paragraph (a)(6) of this section, an instrument using an air or O_2 dilution and oxidation system to convert the reduced sulfur to SO_2 for continuously monitoring and recording the concentration (dry basis, zero percent excess air) of the resultant SO_2. The monitor shall include an oxygen monitor for correcting the data for excess oxygen.

(i) The span values for this monitor are 375 ppm SO_2 and 25 percent O_2.

(ii) For reporting purposes, the SO_2 exceedance level for this monitor is 250 ppm (dry basis, zero percent excess air).

(iii) The performance evaluations for this SO_2 (and O_2) monitor under § 60.13(c) shall use Performance Specification 5. Methods 15 or 15A and Method 3 shall be used for conducting the relative accuracy evaluations.

(8) An instrument for continuously monitoring and recording concentrations of SO_2 in the gases at both the inlet and outlet of the SO_2 control device from any fluid catalytic cracking unit catalyst regenerator for which the owner or operator seeks to comply specifically with the 90 percent reduction option under § 60.104(b)(1).

(i) The span value of the inlet monitor shall be set at 125 percent of the maximum estimated hourly potential SO_2 emission concentration entering the control device, and the span value of the outlet monitor shall be set at 50 percent of the maximum estimated hourly potential SO_2 emission concentration entering the control device.

(ii) The performance evaluations for these SO_2 monitors under § 60.13(c) shall use Performance Specification 2. Methods 6 or 6C and 3 or 3A shall be used for conducting the relative accuracy evaluations.

(9) An instrument for continuously monitoring and recording concentrations of SO_2 in the gases discharged into the atmosphere from any fluid catalytic cracking unit catalyst regenerator for which the owner or operator seeks to comply specifically with the 50 ppmv emission limit under § 60.104 (b)(1).

(i) The span value of the monitor shall be set at 50 percent of the maximum hourly potential SO_2 emission concentration of the control device.

(ii) The performance evaluations for this SO_2 monitor under § 60.13 (c) shall use Performance Specification 2. Methods 6 or 6C and 3 or 3A shall be used for conducting the relative accuracy evaluations.

(10) An instrument for continuously monitoring and recording concentrations of oxygen (O_2) in the gases at both the inlet and outlet of the sulfur dioxide control device (or the outlet only if specifically complying with the 50 ppmv standard) from any fluid catalytic cracking unit catalyst regenerator for which the owner or operator has elected to comply with § 60.104(b)(1). The span of this continuous monitoring system shall be set at 10 percent.

(11) The continuous monitoring systems under paragraphs (a)(8), (a)(9), and (a)(10) of this section are operated and data recorded during all periods of operation of the affected facility including periods of startup, shutdown, or malfunction, except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments.

(12) The owner or operator shall use the following procedures to evaluate the continuous monitoring systems under paragraphs (a)(8), (a)(9), and (a)(10) of this section.

(i) Method 3 or 3A and Method 6 or 6C for the relative accuracy evaluations under the § 60.13(e) performance evaluation.

(ii) Appendix F, Procedure 1, including quarterly accuracy determinations and daily calibration drift tests.

(13) When seeking to comply with § 60.104(b)(1), when emission data are not obtained because of continuous monitoring system breakdowns, repairs, calibration checks and zero and span adjustments, emission data will be obtained by using one of the following methods to provide emission data for a minimum of 18 hours per day in at least 22 out of 30 rolling successive calendar days.

(i) The test methods as described in § 60.106(k);

(ii) A spare continuous monitoring system; or

(iii) Other monitoring systems as approved by the Administrator.

(b) An owner or operator may demonstrate that a fuel gas stream combusted in a fuel gas combustion device subject to § 60.104(a)(1) that is not specifically exempted in § 60.105(a)(4)(iv) is inherently low in sulfur. A fuel gas stream that is determined to be low-sulfur is exempt from the monitoring requirements in paragraphs (a)(3) and (4) of this section until there are changes in operating conditions or stream composition.

(1) The owner or operator shall submit to the Administrator a written application for an exemption from monitoring. The application must contain the following information:

(i) A description of the fuel gas stream/system to be considered, including submission of a portion of the appropriate piping diagrams indicating the boundaries of the fuel gas stream/system, and the affected fuel gas combustion device(s) to be considered;

(ii) A statement that there are no crossover or entry points for sour gas (high H_2S content) to be introduced into the fuel gas stream/system (this should be shown in the piping diagrams);

(iii) An explanation of the conditions that ensure low amounts of sulfur in the fuel gas stream (i.e., control equipment or product specifications) at all times;

(iv) The supporting test results from sampling the requested fuel gas stream/system demonstrating that the sulfur content is less than 5 ppmv. Sampling data must include, at minimum, 2 weeks of daily monitoring (14 grab samples) for frequently operated fuel gas streams/systems; for infrequently operated fuel gas streams/systems, seven grab samples must be collected unless other additional information would support reduced sampling. The owner or operator shall use detector tubes ("length-of-stain tube" type measurement) following the "Gas Processors Association Standard 2377–86 (incorporated by reference—see § 60.17), using tubes with a maximum span between 10 and 40 ppmv inclusive when 1≤N≤10, where N = number of pump strokes, to test the applicant fuel gas stream for H_2S; and

(v) A description of how the 2 weeks (or seven samples for infrequently operated fuel gas streams/systems) of monitoring results compares to the typical range of H_2S concentration (fuel quality) expected for the fuel gas stream/system going to the affected fuel gas combustion device (e.g., the 2 weeks of daily detector tube results for a frequently operated loading rack included the entire range of products loaded out, and, therefore, should be representative of typical operating conditions affecting H_2S content in the fuel gas stream going to the loading rack flare).

(2) The effective date of the exemption is the date of submission of the information required in paragraph (b)(1) of this section).

(3) No further action is required unless refinery operating conditions change in such a way that affects the exempt fuel gas stream/system (e.g., the stream composition changes). If such a change occurs, the owner or operator will follow the procedures in paragraph (b)(3)(i), (b)(3)(ii), or (b)(3)(iii) of this section.

(i) If the operation change results in a sulfur content that is still within the range of concentrations included in the original application, the owner or operator shall conduct an H_2S test on a grab sample and record the results as proof that the concentration is still within the range.

(ii) If the operation change results in a sulfur content that is outside the range of concentrations included in the original application, the owner or operator may submit new information following the procedures of paragraph (b)(1) of this section within 60 days (or within 30 days after the seventh grab sample is tested for infrequently operated process units).

(iii) If the operation change results in a sulfur content that is outside the range of concentrations included in the original application and the owner or operator chooses not to submit new information to support an exemption, the owner or operator must begin H_2S monitoring using daily stain sampling to demonstrate compliance using length-of stain tubes with a maximum span between 200 and 400 ppmv inclusive when 1≤N≤5, where N = number of pump strokes. The owner or operator must begin monitoring according to the requirements in paragraph (a)(1) or (2) of this section as soon as practicable but in no case later than 180 days after the operation change. During daily stain tube sampling, a daily sample exceeding 162 ppmv is an exceedance of the 3-hour H_2S concentration limit.

(c) The average coke burn-off rate (Mg (tons) per hour) and hours of operation shall be recorded daily for any fluid catalytic cracking unit catalyst regenerator subject to § 60.102, § 60.103, or § 60.104(b)(2).

(d) For any fluid catalytic cracking unit catalyst regenerator under § 60.102 that uses an incinerator-waste heat boiler to combust the exhaust gases from the catalyst regenerator, the owner or operator shall record daily the rate of combustion of liquid or solid fossil-fuels and the hours of operation during which liquid or solid fossil-fuels are combusted in the incinerator-waste heat boiler.

(e) For the purpose of reports under § 60.7(c), periods of excess emissions that shall be determined and reported are defined as follows:

Note: All averages, except for opacity, shall be determined as the arithmetic average of the applicable 1-hour averages, e.g., the rolling 3-hour average shall be determined as the arithmetic average of three contiguous 1-hour averages.

(1) ***Opacity.*** All 1-hour periods that contain two or more 6-minute periods during which the average opacity as measured by the continuous monitoring system under § 60.105(a)(1) exceeds 30 percent.

(2) ***Carbon monoxide.*** All 1-hour periods during which the average CO concentration as measured by the CO continuous monitoring system under § 60.105(a)(2) exceeds 500 ppm.

(3) ***Sulfur dioxide from fuel gas combustion.***

(i) All rolling 3-hour periods during which the average concentration of SO_2 as measured by the SO_2 continuous monitoring system under § 60.105(a)(3) exceeds 20 ppm (dry basis, zero percent excess air); or

(ii) All rolling 3-hour periods during which the average concentration of H_2S as measured by the H_2S continuous monitoring system under § 60.105(a)(4) exceeds 230 mg/dscm (0.10 gr/dscf).

(4) ***Sulfur dioxide from Claus sulfur recovery plants.***

(i) All 12-hour periods during which the average concentration of SO_2 as measured by the SO_2 continuous monitoring system under § 60.105(a)(5) exceeds 250 ppm (dry basis, zero percent excess air); or

(ii) All 12-hour periods during which the average concentration of reduced sulfur (as SO_2) as measured by the reduced sulfur continuous monitoring system under § 60.105(a)(6) exceeds 300 ppm; or

(iii) All 12-hour periods during which the average concentration of SO_2 as measured by the SO_2 continuous monitoring system under § 60.105(a)(7) exceeds 250 ppm (dry basis, zero percent excess air).

[39 FR 9315, Mar. 8, 1974, as amended at 40 FR 46259, Oct. 6, 1975; 42 FR 32427, June 24, 1977; 42 FR 39389, Aug. 4, 1977; 43 FR 10869, Mar. 15, 1978; 48 FR 23611, May 25, 1983; 50 FR 31701, Aug. 5, 1985; 54 FR 34028, Aug. 17, 1989; 55 FR 40175, Oct. 2, 1990; 65 FR 61754, Oct. 17, 2000; 73 FR 35866, June 24, 2008; 80 FR 75229, Dec. 1, 2015]

§ 60.106 Test methods and procedures.

(a) In conducting the performance tests required in § 60.8, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided in § 60.8(b).

(b) The owner or operator shall determine compliance with the particulate matter (PM) standards in § 60.102(a) as follows:

(1) The emission rate (E) of PM shall be computed for each run using the following equation:

$$E = \frac{c_s Q_{sd}}{K R_c}$$

Where:

E = Emission rate of PM, kg/Mg (lb/ton) of coke burn-off.

c_s = Concentration of PM, g/dscm (gr/dscf).

Q_{sd} = Volumetric flow rate of effluent gas, dscm/hr (dscf/hr).

R_c = Coke burn-off rate, Mg/hr (ton/hr) coke.

K = Conversion factor, 1,000 g/kg (7,000 gr/lb).

(2) Method 5B or 5F is to be used to determine particulate matter emissions and associated moisture content from affected facilities without wet FGD systems; only Method 5B is to be used after wet FGD systems. The sampling time for each run shall be at least 60 minutes and the sampling rate shall be at least 0.015 dscm/min (0.53 dscf/min), except that shorter sampling times may be approved by the Administrator when process variables or other factors preclude sampling for at least 60 minutes.

(3) The coke burn-off rate (R_c) shall be computed for each run using the following equation:

$$R_c = K_1 Q_r (\%CO_2 + \%CO) + K_2 Q_a - K_3 Q_r (\%CO/2 + \%CO_2 + \%O_2) + K_3 Q_{oxy} (\%O_{oxy})$$

Where:

R_c = Coke burn-off rate, kilograms per hour (kg/hr) (lb/hr).

Q_r = Volumetric flow rate of exhaust gas from fluid catalytic cracking unit regenerator before entering the emission control system, dscm/min (dscf/min).

Q_a = Volumetric flow rate of air to fluid catalytic cracking unit regenerator, as determined from the fluid catalytic cracking unit control room instrumentation, dscm/min (dscf/min).

Q_{oxy} = Volumetric flow rate of O_2 enriched air to fluid catalytic cracking unit regenerator, as determined from the fluid catalytic cracking unit control room instrumentation, dscm/min (dscf/min).

$\%CO_2$ = Carbon dioxide concentration in fluid catalytic cracking unit regenerator exhaust, percent by volume (dry basis).

%CO = CO concentration in FCCU regenerator exhaust, percent by volume (dry basis).

$\%O_2$ = O_2 concentration in fluid catalytic cracking unit regenerator exhaust, percent by volume (dry basis).

$\%O_{oxy}$ = O_2 concentration in O_2 enriched air stream inlet to the fluid catalytic cracking unit regenerator, percent by volume (dry basis).

K_1 = Material balance and conversion factor, 0.2982 (kg-min)/(hr-dscm-%) [0.0186 (lb-min)/(hr-dscf-%)].

K_2 = Material balance and conversion factor, 2.088 (kg-min)/(hr-dscm) [0.1303 (lb-min)/(hr-dscf)].

K_3 = Material balance and conversion factor, 0.0994 (kg-min)/(hr-dscm-%) [0.00624 (lb-min)/(hr-dscf-%)].

(i) Method 2 shall be used to determine the volumetric flow rate (Q_r).

(ii) The emission correction factor, integrated sampling and analysis procedure of Method 3B shall be used to determine CO_2, CO, and O_2 concentrations.

(4) Method 9 and the procedures of § 60.11 shall be used to determine opacity.

(c) If auxiliary liquid or solid fossil-fuels are burned in an incinerator-waste heat boiler, the owner or operator shall determine the emission rate of PM permitted in § 60.102(b) as follows:

(1) The allowable emission rate (E_s) of PM shall be computed for each run using the following equation:

$$E_s = F + A (H/R_c)$$

Where:

E_s = Emission rate of PM allowed, kg/Mg (lb/ton) of coke burn-off in catalyst regenerator.

F = Emission standard, 1.0 kg/Mg (2.0 lb/ton) of coke burn-off in catalyst regenerator.

A = Allowable incremental rate of PM emissions, 43 g/GJ (0.10 lb/million Btu).

H = Heat input rate from solid or liquid fossil fuel, GJ/hr (million Btu/hr).

R_c = Coke burn-off rate, Mg coke/hr (ton coke/hr).

(2) Procedures subject to the approval of the Administrator shall be used to determine the heat input rate.

(3) The procedure in paragraph (b)(3) of this section shall be used to determine the coke burn-off rate (R_c).

(d) The owner or operator shall determine compliance with the CO standard in § 60.103(a) by using the integrated sampling technique of Method 10 to determine the CO concentration (dry basis). The sampling time for each run shall be 60 minutes.

(e)

(1) The owner or operator shall determine compliance with the H_2S standard in § 60.104(a)(1) as follows: Method 11, 15, 15A, or 16 shall be used to determine the H_2S concentration. The gases entering the sampling train should be at about atmospheric pressure. If the pressure in the refinery fuel gas lines is relatively high, a flow control valve may be used to reduce the pressure. If the line pressure is high enough to operate the sampling train without a vacuum pump, the pump may be eliminated from the sampling train. The sample shall be drawn from a point near the centroid of the fuel gas line.

(i) For Method 11, the sampling time and sample volume shall be at least 10 minutes and 0.010 dscm (0.35 dscf). Two samples of equal sampling times shall be taken at about 1-hour intervals. The arithmetic average of these two samples shall constitute a run. For most fuel gases, sampling times exceeding 20 minutes may result in depletion of the collection solution, although fuel gases containing low concentrations of H_2S may necessitate sampling for longer periods of time.

(ii) For Method 15 or 16, at least three injects over a 1-hour period shall constitute a run.

(iii) For Method 15A, a 1-hour sample shall constitute a run.

(2) Where emissions are monitored by § 60.105(a)(3), compliance with § 60.104(a)(1) shall be determined using Method 6 or 6C and Method 3 or 3A. The method ANSI/ASME PTC 19.10–1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 6. A 1-hour sample shall constitute a run. Method 6 samples shall be taken at a rate of approximately 2 liters/min. The ppm correction factor (Method 6) and the sampling location in paragraph (f)(1) of this section apply. Method 4 shall be used to determine the moisture content of the gases. The sampling point for Method 4 shall be adjacent to the sampling point for Method 6 or 6C.

(f) The owner or operator shall determine compliance with the SO_2 and the H_2S and reduced sulfur standards in § 60.104(a)(2) as follows:

(1) Method 6 shall be used to determine the SO_2 concentration. The concentration in mg/dscm obtained by Method 6 or 6C is multiplied by 0.3754 to obtain the concentration in ppm. The sampling point in the duct shall be the centroid of the cross section if the cross-sectional area is less than 5.00 m^2 (53.8 ft^2) or at a point no closer to the walls than 1.00 m (39.4 in.) if the cross-sectional area is 5.00 m^2 or more and the centroid is more than 1 m from the wall. The sampling time and sample volume shall be at least 10 minutes and 0.010 dscm (0.35 dscf) for each sample. Eight samples of equal sampling times shall be taken at about 30-minute intervals. The arithmetic average of these eight samples shall constitute a run. For Method 6C, a run shall consist of the arithmetic average of four 1-hour samples. Method 4 shall be used to determine the moisture content of the gases. The sampling point for Method 4 shall be adjacent to the sampling point for Method 6 or 6C. The sampling time for each sample shall be equal to the time it takes for two Method 6 samples. The moisture content from this sample shall be used to correct the corresponding Method 6 samples for moisture. For documenting the oxidation efficiency of the control device for reduced sulfur compounds, Method 15 shall be used following the procedures of paragraph (f)(2) of this section.

(2) Method 15 shall be used to determine the reduced sulfur and H_2 S concentrations. Each run shall consist of 16 samples taken over a minimum of 3 hours. The sampling point shall be the same as that described for Method 6 in paragraph (f)(1) of this section. To ensure minimum residence time for the sample inside the sample lines, the sampling rate shall be at least 3.0 lpm (0.10 cfm). The

SO_2 equivalent for each run shall be calculated after being corrected for moisture and oxygen as the arithmetic average of the SO_2 equivalent for each sample during the run. Method 4 shall be used to determine the moisture content of the gases as the paragraph (f)(1) of this section. The sampling time for each sample shall be equal to the time it takes for four Method 15 samples.

(3) The oxygen concentration used to correct the emission rate for excess air shall be obtained by the integrated sampling and analysis procedure of Method 3 or 3A. The samples shall be taken simultaneously with the SO_2, reduced sulfur and H_2S, or moisture samples. The SO_2, reduced sulfur, and H_2S samples shall be corrected to zero percent excess air using the equation in paragraph (h)(6) of this section.

(g) Each performance test conducted for the purpose of determining compliance under § 60.104(b) shall consist of all testing performed over a 7-day period using Method 6 or 6C and Method 3 or 3A. To determine compliance, the arithmetic mean of the results of all the tests shall be compared with the applicable standard.

(h) For the purpose of determining compliance with § 60.104(b)(1), the following calculation procedures shall be used:

(1) Calculate each 1-hour average concentration (dry, zero percent oxygen, ppmv) of sulfur dioxide at both the inlet and the outlet to the add-on control device as specified in § 60.13(h). These calculations are made using the emission data collected under § 60.105(a).

(2) Calculate a 7-day average (arithmetic mean) concentration of sulfur dioxide for the inlet and for the outlet to the add-on control device using all of the 1-hour average concentration values obtained during seven successive 24-hour periods.

(3) Calculate the 7-day average percent reduction using the following equation:

$$R_{SO_2} = 100(C_{SO_2}(i) - C_{SO_2}(o)) / C_{SO_2}(i)$$

where:

R_{SO_2} = 7-day average sulfur dioxide emission reduction, percent

$C_{SO_2}(i)$ = sulfur dioxide emission concentration determined in § 60.106(h)(2) at the inlet to the add-on control device, ppmv

$C_{SO_2}(o)$ = sulfur dioxide emission concentration determined in § 60.106(h)(2) at the outlet to the add-on control device, ppmv

100 = conversion factor, decimal to percent

(4) Outlet concentrations of sulfur dioxide from the add-on control device for compliance with the 50 ppmv standard, reported on a dry, O_2-free basis, shall be calculated using the procedures outlined in § 60.106(h)(1) and (2) above, but for the outlet monitor only.

(5) If supplemental sampling data are used for determining the 7-day averages under paragraph (h) of this section and such data are not hourly averages, then the value obtained for each supplemental sample shall be assumed to represent the hourly average for each hour over which the sample was obtained.

(6) For the purpose of adjusting pollutant concentrations to zero percent oxygen, the following equation shall be used:

$$C_{adj} = C_{meas}[20.9_c/(20.9-\%O_2)]$$

where:

C_{adj} = pollutant concentration adjusted to zero percent oxygen, ppm or g/dscm

C_{meas} = pollutant concentration measured on a dry basis, ppm or g/dscm

20.9_c = 20.9 percent oxygen−0.0 percent oxygen (defined oxygen correction basis), percent

20.9 = oxygen concentration in air, percent

$\%O_2$ = oxygen concentration measured on a dry basis, percent

(i) For the purpose of determining compliance with § 60.104(b)(2), the following reference methods and calculation procedures shall be used except as provided in paragraph (i)(12) of this section:

(1) One 3-hour test shall be performed each day.

(2) For gases released to the atmosphere from the fluid catalytic cracking unit catalyst regenerator:

(i) Method 8 as modified in § 60.106(i)(3) for moisture content and for the concentration of sulfur oxides calculated as sulfur dioxide,

(ii) Method 1 for sample and velocity traverses,

(iii) Method 2 calculation procedures (data obtained from Methods 3 and 8) for velocity and volumetric flow rate, and

(iv) Method 3 for gas analysis.

(3) Method 8 shall be modified by the insertion of a heated glass fiber filter between the probe and first impinger. The probe liner and glass fiber filter temperature shall be maintained above 160 °C (320 °F). The isopropanol impinger shall be eliminated. Sample recovery procedures described in Method 8 for container No. 1 shall be eliminated. The heated glass fiber filter also shall be excluded; however, rinsing of all connecting glassware after the heated glass fiber filter shall be retained and included in container No. 2. Sampled volume shall be at least 1 dscm.

(4) For Method 3, the integrated sampling technique shall be used.

(5) Sampling time for each run shall be at least 3 hours.

(6) All testing shall be performed at the same location. Where the gases discharged by the fluid catalytic cracking unit catalyst regenerator pass through an incinerator-waste heat boiler in which auxiliary or supplemental gaseous, liquid, or solid fossil fuel is burned, testing shall be conducted at a point between the regenerator outlet and the incinerator-waste heat boiler. An alternative sampling location after the waste heat boiler may be used if alternative coke burn-off rate equations, and, if requested, auxiliary/supplemental fuel SO_X credits, have been submitted to and approved by the Administrator prior to sampling.

(7) Coke burn-off rate shall be determined using the procedures specified under paragraph (b)(3) of this section, unless paragraph (i)(6) of this section applies.

(8) Calculate the concentration of sulfur oxides as sulfur dioxide using equation 8–3 in Section 6.5 of Method 8 to calculate and report the total concentration of sulfur oxides as sulfur dioxide (Cso_x).

(9) Sulfur oxides emission rate calculated as sulfur dioxide shall be determined for each test run by the following equation:

$$E_{so_x} = C_{so_x} Q_{sd}/K$$

Where:

E_{SOx} = sulfur oxides emission rate calculated as sulfur dioxide, kg/hr (lb/hr)

C_{SOx} = sulfur oxides emission concentration calculated as sulfur dioxide, g/dscm (gr/dscf)

Q_{sd} = dry volumetric stack gas flow rate corrected to standard conditions, dscm/hr (dscf/hr)

K = 1,000 g/kg (7,000 gr/lb)

(10) Sulfur oxides emissions calculated as sulfur dioxide shall be determined for each test run by the following equation:

$$R_{so_x} = \left(E_{so_x}/R_c\right)$$

Where:

R_{SOx} = Sulfur oxides emissions calculated as kg sulfur dioxide per Mg (lb/ton) coke burn-off.

E_{SOx} = Sulfur oxides emission rate calculated as sulfur dioxide, kg/hr (lb/hr).

R_c = Coke burn-off rate, Mg/hr (ton/hr).

(11) Calculate the 7-day average sulfur oxides emission rate as sulfur dioxide per Mg (ton) of coke burn-off by dividing the sum of the individual daily rates by the number of daily rates summed.

(12) An owner or operator may, upon approval by the Administrator, use an alternative method for determining compliance with § 60.104(b)(2), as provided in § 60.8(b). Any requests for approval must include data to demonstrate to the Administrator that the alternative method would produce results adequate for the determination of compliance.

(j) For the purpose of determining compliance with § 60.104(b)(3), the following analytical methods and calculation procedures shall be used:

(1) One fresh feed sample shall be collected once per 8-hour period.

(2) Fresh feed samples shall be analyzed separately by using any one of the following applicable analytical test methods: ASTM D129–64, 78, or 95, ASTM D1552–83 or 95, ASTM D2622–87, 94, or 98, or ASTM D1266–87, 91, or 98. (These methods are incorporated by reference: see § 60.17.) The

applicable range of some of these ASTM methods is not adequate to measure the levels of sulfur in some fresh feed samples. Dilution of samples prior to analysis with verification of the dilution ratio is acceptable upon prior approval of the Administrator.

(3) If a fresh feed sample cannot be collected at a single location, then the fresh feed sulfur content shall be determined as follows:

(i) Individual samples shall be collected once per 8-hour period for each separate fresh feed stream charged directly into the riser or reactor of the fluid catalytic cracking unit. For each sample location the fresh feed volumetric flow rate at the time of collecting the fresh feed sample shall be measured and recorded. The same method for measuring volumetric flow rate shall be used at all locations.

(ii) Each fresh feed sample shall be analyzed separately using the methods specified under paragraph (j)(2) of this section.

(iii) Fresh feed sulfur content shall be calculated for each 8-hour period using the following equation:

$$S_f = \sum_{i=1}^{n} \frac{S_i Q_i}{Q_f}$$

where:

S_f = fresh feed sulfur content expressed in percent by weight of fresh feed.

n = number of separate fresh feed streams charged directly to the riser or reactor of the fluid catalytic cracking unit.

Q_f = total volumetric flow rate of fresh feed charged to the fluid catalytic cracking unit.

S_i = fresh feed sulfur content expressed in percent by weight of fresh feed for the “ith” sampling location.

Q_i = volumetric flow rate of fresh feed stream for the “ith” sampling location.

(4) Calculate a 7-day average (arithmetic mean) sulfur content of the fresh feed using all of the fresh feed sulfur content values obtained during seven successive 24-hour periods.

(k) The test methods used to supplement continuous monitoring system data to meet the minimum data requirements in § 60.104(d) will be used as described below or as otherwise approved by the Administrator.

(1) Methods 6, 6B, or 8 are used. The sampling location(s) are the same as those specified for the monitor.

(2) For Method 6, the minimum sampling time is 20 minutes and the minimum sampling volume is 0.02 dscm (0.71 dscf) for each sample. Samples are taken at approximately 60-minute intervals. Each sample represents a 1-hour average. A minimum of 18 valid samples is required to obtain one valid day of data.

(3) For Method 6B, collection of a sample representing a minimum of 18 hours is required to obtain one valid day of data.

(4) For Method 8, the procedures as outlined in this section are used. The equivalent of 16 hours of sampling is required to obtain one valid day of data.

[39 FR 9315, Mar. 8, 1974, as amended at 43 FR 10869, Mar. 15, 1978; 51 FR 42842, Nov. 26, 1986; 52 FR 20392, June 1, 1987; 53 FR 41333, Oct. 21, 1988; 54 FR 34028, Aug. 17, 1989; 55 FR 40176, Oct. 2, 1990; 56 FR 4176, Feb. 4, 1991; 65 FR 61754, Oct. 17, 2000; 71 FR 55127, Sept. 21, 2006; 73 FR 35867, June 24, 2008; 77 FR 56463, Sep. 12, 2012]

§ 60.107 Reporting and recordkeeping requirements.

(a) Each owner or operator subject to § 60.104(b) shall notify the Administrator of the specific provisions of § 60.104(b) with which the owner or operator seeks to comply. Notification shall be submitted with the notification of initial startup required by § 60.7(a)(3). If an owner or operator elects at a later date to comply with an alternative provision of § 60.104(b), then the Administrator shall be notified by the owner or operator in the report described in paragraph (c) of this section.

(b) Each owner or operator subject to § 60.104(b) shall record and maintain the following information:

(1) If subject to § 60.104(b)(1),

(i) All data and calibrations from continuous monitoring systems located at the inlet and outlet to the control device, including the results of the daily drift tests and quarterly accuracy assessments required under appendix F, Procedure 1;

(ii) Measurements obtained by supplemental sampling (refer to § 60.105(a)(13) and § 60.106(k)) for meeting minimum data requirements; and

(iii) The written procedures for the quality control program required by appendix F, Procedure 1.

(2) If subject to § 60.104(b)(2), measurements obtained in the daily Method 8 testing, or those obtained by alternative measurement methods, if § 60.106(i)(12) applies.

(3) If subject to § 60.104(b)(3), data obtained from the daily feed sulfur tests.

(4) Each 7-day rolling average compliance determination.

(c) Each owner or operator subject to § 60.104(b) shall submit a report except as provided by paragraph (d) of this section. The following information shall be contained in the report:

(1) Any 7-day period during which:

(i) The average percent reduction and average concentration of sulfur dioxide on a dry, O_2-free basis in the gases discharged to the atmosphere from any fluid cracking unit catalyst regenerator for which the owner or operator seeks to comply with § 60.104(b)(1) is below 90 percent and above 50 ppmv, as measured by the continuous monitoring system prescribed under § 60.105(a)(8), or above 50 ppmv, as measured by the outlet continuous monitoring system prescribed under § 60.105(a)(9). The average percent reduction and average sulfur dioxide concentration shall be determined using the procedures specified under § 60.106(h);

(ii) The average emission rate of sulfur dioxide in the gases discharged to the atmosphere from any fluid catalytic cracking unit catalyst regenerator for which the owner or operator seeks to comply with § 60.104(b)(2) exceeds 9.8 kg SO_X per 1,000 kg coke burn-off, as measured by the daily testing prescribed under § 60.106(i). The average emission rate shall be determined using the procedures specified under § 60.106(i); and

(iii) The average sulfur content of the fresh feed for which the owner or operator seeks to comply with § 60.104(b)(3) exceeds 0.30 percent by weight. The fresh feed sulfur content, a 7-day rolling average, shall be determined using the procedures specified under § 60.106(j).

(2) Any 30-day period in which the minimum data requirements specified in § 60.104(d) are not obtained.

(3) For each 7-day period during which an exceedance has occurred as defined in paragraphs (c)(1)(i) through (c)(1)(iii) and (c)(2) of this section:

(i) The date that the exceedance occurred;

(ii) An explanation of the exceedance;

(iii) Whether the exceedance was concurrent with a startup, shutdown, or malfunction of the fluid catalytic cracking unit or control system; and

(iv) A description of the corrective action taken, if any.

(4) If subject to § 60.104(b)(1),

(i) The dates for which and brief explanations as to why fewer than 18 valid hours of data were obtained for the inlet continuous monitoring system;

(ii) The dates for which and brief explanations as to why fewer than 18 valid hours of data were obtained for the outlet continuous monitoring system;

(iii) Identification of times when hourly averages have been obtained based on manual sampling methods;

(iv) Identification of the times when the pollutant concentration exceeded full span of the continuous monitoring system; and

(v) Description of any modifications to the continuous monitoring system that could affect the ability of the continuous monitoring system to comply with Performance Specifications 2 or 3.

(vi) Results of daily drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1.

(5) If subject to § 60.104(b)(2), for each day in which a Method 8 sample result required by § 60.106(i) was not obtained, the date for which and brief explanation as to why a Method 8 sample result was not obtained, for approval by the Administrator.

(6) If subject to § 60.104(b)(3), for each 8-hour period in which a feed sulfur measurement required by § 60.106(j) was not obtained, the date for which and brief explanation as to why a feed sulfur measurement was not obtained, for approval by the Administrator.

(d) For any periods for which sulfur dioxide or oxides emissions data are not available, the owner or operator of the affected facility shall submit a signed statement indicating if any changes were made in operation of the emission control system during the period of data unavailability which could affect the ability of the system to meet the applicable emission limit. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation of the control system and affected facility before and following the period of data unavailability.

(e) For each fuel gas stream combusted in a fuel gas combustion device subject to § 60.104(a)(1), if an owner or operator determines that one of the exemptions listed in § 60.105(a)(4)(iv) applies to that fuel gas stream, the owner or operator shall maintain records of the specific exemption chosen for each fuel gas stream. If the owner or operator applies for the exemption described in § 60.105(a)(4)(iv)(D), the owner or operator must keep a copy of the application as well as the letter from the Administrator granting approval of the application.

(f) The owner or operator of an affected facility shall submit the reports required under this subpart to the Administrator semiannually for each six-month period. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period.

(g) The owner or operator of the affected facility shall submit a signed statement certifying the accuracy and completeness of the information contained in the report.

[54 FR 34029, Aug. 17, 1989, as amended at 55 FR 40178, Oct. 2, 1990; 64 FR 7465, Feb. 12, 1999; 65 FR 61755, Oct. 17, 2000; 73 FR 35867, June 24, 2008]

§ 60.108 Performance test and compliance provisions.

(a) Section 60.8(d) shall apply to the initial performance test specified under paragraph (c) of this section, but not to the daily performance tests required thereafter as specified in § 60.108(d). Section 60.8(f) does not apply when determining compliance with the standards specified under § 60.104(b). Performance tests conducted for the purpose of determining compliance under § 60.104(b) shall be conducted according to the applicable procedures specified under § 60.106.

(b) Owners or operators who seek to comply with § 60.104(b)(3) shall meet that standard at all times, including periods of startup, shutdown, and malfunctions.

(c) The initial performance test shall consist of the initial 7-day average calculated for compliance with § 60.104(b)(1), (b)(2), or (b)(3).

(d) After conducting the initial performance test prescribed under § 60.8, the owner or operator of a fluid catalytic cracking unit catalyst regenerator subject to § 60.104(b) shall conduct a performance test for each successive 24-hour period thereafter. The daily performance tests shall be conducted according to the appropriate procedures specified under § 60.106. In the event that a sample collected under § 60.106(i) or (j) is accidentally lost or conditions occur in which one of the samples must be discontinued because of forced shutdown, failure of an irreplaceable portion of the sample train, extreme meteorological conditions, or other circumstances, beyond the owner or operators' control, compliance may be determined using available data for the 7-day period.

(e) Each owner or operator subject to § 60.104(b) who has demonstrated compliance with one of the provisions of § 60.104(b) but a later date seeks to comply with another of the provisions of § 60.104(b) shall begin conducting daily performance tests as specified under paragraph (d) of this section immediately upon electing to become subject to one of the other provisions of § 60.104(b). The owner or operator shall furnish the Administrator with a written notification of the change in the semiannual report required by § 60.107(f).

[54 FR 34030, Aug. 17, 1989, as amended at 55 FR 40178, Oct. 2, 1990; 64 FR 7466, Feb. 12, 1999; 73 FR 35867, June 24, 2008]

§ 60.109 Delegation of authority.

(a) In delegating implementation and enforcement authority to a State under section 111(c) of the Act, the authorities contained in paragraph (b) of this section shall be retained by the Administrator and not transferred to a State.

(b) Authorities which shall not be delegated to States:

(1) Section 60.105(a)(13)(iii),

(2) Section 60.106(i)(12).

[54 FR 34031, Aug. 17, 1989, as amended at 55 FR 40178, Oct. 2, 1990]

Appendix B

40 C.F.R. § 60 Subpart Ja—*Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007*

Title 40 —Protection of Environment
Chapter I —Environmental Protection Agency
Subchapter C —Air Programs
Part 60 —Standards of Performance for New Stationary Sources

Authority: 42 U.S.C. 7401 *et seq.*
Source: 36 FR 24877, Dec. 23, 1971, unless otherwise noted.

Subpart Ja—Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007

Source: 73 FR 35867, June 24, 2008, unless otherwise noted.

§ 60.100a Applicability, designation of affected facility, and reconstruction.

(a) The provisions of this subpart apply to the following affected facilities in petroleum refineries: fluid catalytic cracking units (FCCU), fluid coking units (FCU), delayed coking units, fuel gas combustion devices (including process heaters), flares and sulfur recovery plants. The sulfur recovery plant need not be physically located within the boundaries of a petroleum refinery to be an affected facility, provided it processes gases produced within a petroleum refinery.

(b) Except for flares and delayed coking units, the provisions of this subpart apply only to affected facilities under paragraph (a) of this section which either commence construction, modification or reconstruction after May 14, 2007, or elect to comply with the provisions of this subpart in lieu of complying with the provisions in subpart J of this part. For flares, the provisions of this subpart apply only to flares which commence construction, modification or reconstruction after June 24, 2008. For the purposes of this subpart, a modification to a flare commences when a project that includes any of the activities in paragraphs (c)(1) or (2) of this section is commenced. For delayed coking units, the provisions of this subpart apply to delayed coking units that commence construction, reconstruction or modification on the earliest of the following dates:

(1) May 14, 2007, for such activities that involve a "delayed coking unit" defined as follows: one or more refinery process units in which high molecular weight petroleum derivatives are thermally cracked and petroleum coke is produced in a series of closed, batch system reactors;

(2) December 22, 2008, for such activities that involve a "delayed coking unit" defined as follows: a refinery process unit in which high molecular weight petroleum derivatives are thermally cracked and petroleum coke is produced in a series of closed, batch system reactors. A delayed coking unit consists of the coke drums and associated fractionator;

(3) September 12, 2012, for such activities that involve a "delayed coking unit" as defined in § 60.101a.

(c) For all affected facilities other than flares, the provisions in § 60.14 regarding modification apply. As provided in § 60.14(f), the special provisions set forth under this subpart shall supersede the provisions in § 60.14 with respect to flares. For the purposes of this subpart, a modification to a flare occurs as provided in paragraphs (c)(1) or (2) of this section.

(1) Any new piping from a refinery process unit, including ancillary equipment, or a fuel gas system is physically connected to the flare (*e.g.,* for direct emergency relief or some form of continuous or intermittent venting). However, the connections described in paragraphs (c)(1)(i) through (vii) of this section are not considered modifications of a flare.

(i) Connections made to install monitoring systems to the flare.

(ii) Connections made to install a flare gas recovery system or connections made to upgrade or enhance components of a flare gas recovery system (*e.g.,* addition of compressors or recycle lines).

(iii) Connections made to replace or upgrade existing pressure relief or safety valves, provided the new pressure relief or safety valve has a set point opening pressure no lower and an internal diameter no greater than the existing equipment being replaced or upgraded.

(iv) Connections made for flare gas sulfur removal.

(v) Connections made to install back-up (redundant) equipment associated with the flare (such as a back-up compressor) that does not increase the capacity of the flare.

(vi) Replacing piping or moving an existing connection from a refinery process unit to a new location in the same flare, provided the new pipe diameter is less than or equal to the diameter of the pipe/connection being replaced/moved.

(vii) Connections that interconnect two or more flares.

(2) A flare is physically altered to increase the flow capacity of the flare.

(d) For purposes of this subpart, under § 60.15, the "fixed capital cost of the new components" includes the fixed capital cost of all depreciable components which are or will be replaced pursuant to all continuous programs of component replacement which are commenced within any 2-year period following the relevant applicability date specified in paragraph (b) of this section.

[73 FR 35867, June 24, 2008, as amended at 77 FR 56464, Sep. 12, 2012; 80 FR 75230, Dec. 1, 2015]

§ 60.101a Definitions.

Terms used in this subpart are defined in the Clean Air Act (CAA), in § 60.2 and in this section.

Air preheat means a device used to heat the air supplied to a process heater generally by use of a heat exchanger to recover the sensible heat of exhaust gas from the process heater.

Ancillary equipment means equipment used in conjunction with or that serve a refinery process unit. *Ancillary equipment* includes, but is not limited to, storage tanks, product loading operations, wastewater treatment systems, steam- or electricity-producing units (including coke gasification units), pressure relief valves, pumps, sampling vents and continuous analyzer vents.

Cascaded flare system means a series of flares connected to one flare gas header system arranged with increasing pressure set points so that discharges will be initially directed to the first flare in the series (*i.e.,* the primary flare). If the discharge pressure exceeds a set point at which the flow to the primary flare would exceed the primary flare's capacity, flow will be diverted to the second flare in the series. Similarly, flow would be diverted to a third (or fourth) flare if the pressure in the flare gas header system exceeds a threshold where the flow to the first two (or three) flares would exceed their capacities.

Co-fired process heater means a process heater that employs burners that are designed to be supplied by both gaseous and liquid fuels on a routine basis. Process heaters that have gas burners with emergency oil back-up burners are not considered co-fired process heaters.

Coke burn-off means the coke removed from the surface of the FCCU catalyst by combustion in the catalyst regenerator. The rate of coke burn-off is calculated by the formula specified in § 60.104a.

Contact material means any substance formulated to remove metals, sulfur, nitrogen, or any other contaminant from petroleum derivatives.

Corrective action means the design, operation and maintenance changes that one takes consistent with good engineering practice to reduce or eliminate the likelihood of the recurrence of the primary cause and any other contributing cause(s) of an event identified by a root cause analysis as having resulted in a discharge of gases from an affected facility in excess of specified thresholds.

Corrective action analysis means a description of all reasonable interim and long-term measures, if any, that are available, and an explanation of why the selected corrective action(s) is/are the best alternative(s), including, but not limited to, considerations of cost effectiveness, technical feasibility, safety and secondary impacts.

Delayed coking unit means a refinery process unit in which high molecular weight petroleum derivatives are thermally cracked and petroleum coke is produced in a series of closed, batch system reactors. A *delayed coking unit* includes, but is not limited to, all of the coke drums associated with a single fractionator; the fractionator, including the bottoms receiver and the overhead condenser; the coke drum cutting water and quench system, including the jet pump and coker quench water tank; and the coke drum blowdown recovery compressor system.

Emergency flare means a flare that combusts gas exclusively released as a result of malfunctions (and not startup, shutdown, routine operations or any other cause) on four or fewer occasions in a rolling 365-day period. For purposes of this rule, a flare cannot be categorized as an *emergency flare* unless it maintains a water seal.

Flare means a combustion device that uses an uncontrolled volume of air to burn gases. The *flare* includes the foundation, flare tip, structural support, burner, igniter, flare controls, including air injection or steam injection systems, flame arrestors and the flare gas header system. In the case of an interconnected flare gas header system, the *flare* includes each individual flare serviced by the interconnected flare gas header system and the interconnected flare gas header system.

Flare gas header system means all piping and knockout pots, including those in a subheader system, used to collect and transport gas to a flare either from a process unit or a pressure relief valve from the fuel gas system, regardless of whether or not a flare gas recovery system draws gas from the *flare gas header system.* The *flare gas header system* includes piping inside the battery limit of a process unit if the purpose of the piping is to transport gas to a flare or knockout pot that is part of the flare.

Flare gas recovery system means a system of one or more compressors, piping and the associated water seal, rupture disk or similar device used to divert gas from the flare and direct the gas to the fuel gas system or to a fuel gas combustion device.

Flexicoking unit means a refinery process unit in which high molecular weight petroleum derivatives are thermally cracked and petroleum coke is continuously produced and then gasified to produce a synthetic fuel gas.

Fluid catalytic cracking unit means a refinery process unit in which petroleum derivatives are continuously charged and hydrocarbon molecules in the presence of a catalyst suspended in a fluidized bed are fractured into smaller molecules, or react with a contact material suspended in a fluidized bed to improve feedstock quality for additional processing and the catalyst or contact material is continuously regenerated by burning off coke and other deposits. The unit includes the riser, reactor, regenerator, air blowers, spent catalyst or contact material stripper, catalyst or contact material recovery equipment, and regenerator equipment for controlling air pollutant emissions and for heat recovery. When *fluid catalyst cracking unit* regenerator exhaust from two separate fluid catalytic cracking units share a common exhaust treatment (e.g., CO boiler or wet scrubber), the *fluid catalytic cracking unit* is a single affected facility.

Fluid coking unit means a refinery process unit in which high molecular weight petroleum derivatives are thermally cracked and petroleum coke is continuously produced in a fluidized bed system. The *fluid coking unit* includes the coking reactor, the coking burner, and equipment for controlling air pollutant emissions and for heat recovery on the fluid coking burner exhaust vent.

Forced draft process heater means a process heater in which the combustion air is supplied under positive pressure produced by a fan at any location in the inlet air line prior to the point where the combustion air enters the process heater or air preheat. For the purposes of this subpart, a process heater that uses fans at both the inlet air side and the exhaust air side (*i.e.,* balanced draft system) is considered to be a *forced draft process heater.*

Fuel gas means any gas which is generated at a petroleum refinery and which is combusted. *Fuel gas* includes natural gas when the natural gas is combined and combusted in any proportion with a gas generated at a refinery. *Fuel gas* does not include gases generated by catalytic cracking unit catalyst regenerators, coke calciners (used to make premium grade coke) and fluid coking burners, but does include gases from flexicoking unit gasifiers and other gasifiers. *Fuel gas* does not include vapors that are collected and combusted in a thermal oxidizer or flare installed to control emissions from wastewater treatment units other than those processing sour water, marine tank vessel loading operations or asphalt processing units (*i.e.,* asphalt blowing stills).

Fuel gas combustion device means any equipment, such as process heaters and boilers, used to combust fuel gas. For the purposes of this subpart, *fuel gas combustion device* does not include flares or facilities in which gases are combusted to produce sulfur or sulfuric acid.

Fuel gas system means a system of compressors, piping, knock-out pots, mix drums, and units used to remove sulfur contaminants from the fuel gas (e.g., amine scrubbers) that collects refinery fuel gas from one or more sources for treatment as necessary prior to combusting in process heaters or boilers. A *fuel gas system* may have an overpressure vent to a flare but the primary purpose for a fuel gas system is to provide fuel to the refinery.

Natural draft process heater means any process heater in which the combustion air is supplied under ambient or negative pressure without the use of an inlet air (forced draft) fan. For the purposes of this subpart, a *natural draft process heater* is any process heater that is not a forced draft process heater, including induced draft systems.

Non-emergency flare means any flare that is not an emergency flare as defined in this subpart.

Oxidation control system means an emission control system which reduces emissions from sulfur recovery plants by converting these emissions to sulfur dioxide (SO_2) and recycling the SO_2 to the reactor furnace or the first-stage catalytic reactor of the Claus sulfur recovery plant or converting the SO_2 to a sulfur product.

Petroleum means the crude oil removed from the earth and the oils derived from tar sands, shale, and coal.

Petroleum refinery means any facility engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants, asphalt (bitumen) or other products through distillation of petroleum or through redistillation, cracking or reforming of unfinished petroleum derivatives. A facility that produces only oil shale or tar sands-derived crude oil for further processing at a petroleum refinery using only solvent extraction and/or distillation to recover diluent is not a *petroleum refinery.*

Primary flare means the first flare in a cascaded flare system.

Process heater means an enclosed combustion device used to transfer heat indirectly to process stream materials (liquids, gases, or solids) or to a heat transfer material for use in a process unit instead of steam.

Process upset gas means any gas generated by a petroleum refinery process unit or by ancillary equipment as a result of startup, shutdown, upset or malfunction.

Purge gas means gas introduced between a flare's water seal and a flare's tip to prevent oxygen infiltration (backflow) into the flare tip. For flares with no water seals, the function of *purge gas* is performed by sweep gas (*i.e.,* flares without water seals do not use *purge gas*).

Reduced sulfur compounds means hydrogen sulfide (H_2S), carbonyl sulfide, and carbon disulfide.

Reduction control system means an emission control system which reduces emissions from sulfur recovery plants by converting these emissions to H_2S and either recycling the H_2S to the reactor furnace or the first-stage catalytic reactor of the Claus sulfur recovery plant or converting the H_2S to a sulfur product.

Refinery process unit means any segment of the petroleum refinery in which a specific processing operation is conducted.

Root cause analysis means an assessment conducted through a process of investigation to determine the primary cause, and any other contributing cause(s), of a discharge of gases in excess of specified thresholds.

Secondary flare means a flare in a cascaded flare system that provides additional flare capacity and pressure relief to a flare gas system when the flare gas flow exceeds the capacity of the primary flare. For purposes of this subpart, a *secondary flare* is characterized by infrequent use and must maintain a water seal.

Sour water means water that contains sulfur compounds (usually H_2S) at concentrations of 10 parts per million by weight or more.

Sulfur pit means the storage vessel in which sulfur that is condensed after each Claus catalytic reactor is initially accumulated and stored. *A sulfur pit* does not include secondary sulfur storage vessels downstream of the initial Claus reactor sulfur pits.

Sulfur recovery plant means all process units which recover sulfur from H_2S and/or SO_2 from a common source of sour gas produced at a petroleum refinery. The *sulfur recovery plant* also includes sulfur pits used to store the recovered sulfur product, but it does not include secondary sulfur storage vessels or loading facilities downstream of the sulfur pits. For example, a Claus sulfur recovery plant includes: Reactor furnace and waste heat boiler, catalytic reactors, sulfur pits and, if present, oxidation or reduction control systems or incinerator, thermal oxidizer or similar combustion device. Multiple sulfur recovery units are a single affected facility only when the units share the same source of sour gas. *Sulfur recovery plants* that receive source gas from completely segregated sour gas treatment systems are separate affected facilities.

Sweep gas means the gas introduced in a flare gas header system to maintain a constant flow of gas to prevent oxygen buildup in the flare header. For flares with no water seals, *sweep gas* also performs the function of preventing oxygen infiltration (backflow) into the flare tip.

[73 FR 35867, June 24, 2008, as amended at 77 FR 56464, Sep. 12, 2012; 78 FR 76756, Dec. 19, 2013; 80 FR 75230, Dec. 1, 2015]

§ 60.102a Emissions limitations.

(a) Each owner or operator that is subject to the requirements of this subpart shall comply with the emissions limitations in paragraphs (b) through (i) of this section on and after the date on which the initial performance test, required by § 60.8, is completed, but not later than 60 days after achieving the maximum production rate at which the affected facility will be operated or 180 days after initial startup, whichever comes first.

(b) An owner or operator subject to the provisions of this subpart shall not discharge or cause the discharge into the atmosphere from any FCCU or FCU:

(1) Particulate matter (PM) in excess of the limits in paragraphs (b)(1)(i), (ii), or (iii) of this section.

(i) 1.0 gram per kilogram (g/kg) (1 pound (lb) per 1,000 lb) coke burn-off or, if a PM continuous emission monitoring system (CEMS) is used, 0.040 grain per dry standard cubic feet (gr/dscf) corrected to 0 percent excess air for each modified or reconstructed FCCU.

(ii) 0.5 gram per kilogram (g/kg) coke burn-off (0.5 lb PM/1,000 lb coke burn-off) or, if a PM CEMS is used, 0.020 gr/dscf corrected to 0 percent excess air for each newly constructed FCCU.

(iii) 1.0 g/kg (1 lb/1,000 lb) coke burn-off or, if a PM CEMS is used, 0.040 grain per dry standard cubic feet (gr/dscf) corrected to 0 percent excess air for each affected FCU.

(2) Nitrogen oxides (NO_X) in excess of 80 parts per million by volume (ppmv), dry basis corrected to 0 percent excess air, on a 7-day rolling average basis.

(3) Sulfur dioxide (SO_2) in excess of 50 ppmv dry basis corrected to 0 percent excess air, on a 7-day rolling average basis and 25 ppmv, dry basis corrected to 0 percent excess air, on a 365-day rolling average basis.

(4) Carbon monoxide (CO) in excess of 500 ppmv, dry basis corrected to 0 percent excess air, on an hourly average basis.

(c) The owner or operator of a FCCU or FCU that uses a continuous parameter monitoring system (CPMS) according to § 60.105a(b)(1) shall comply with the applicable control device parameter operating limit in paragraph (c)(1) or (2) of this section.

(1) If the FCCU or FCU is controlled using an electrostatic precipitator:

(i) The 3-hour rolling average total power and secondary current to the entire system must not fall below the level established during the most recent performance test; and

(ii) The daily average exhaust coke burn-off rate must not exceed the level established during the most recent performance test.

(2) If the FCCU or FCU is controlled using a wet scrubber:

(i) The 3-hour rolling average pressure drop must not fall below the level established during the most recent performance test; and

(ii) The 3-hour rolling average liquid-to-gas ratio must not fall below the level established during the most recent performance test.

(d) If an FCCU or FCU uses a continuous opacity monitoring system (COMS) according to the alternative monitoring option in § 60.105a(e), the 3-hour rolling average opacity of emissions from the FCCU or FCU as measured by the COMS must not exceed the site-specific opacity limit established during the most recent performance test.

(e) The owner or operator of a FCCU or FCU that is exempted from the requirement for a CO continuous emissions monitoring system under § 60.105a(h)(3) shall comply with the parameter operating limits in paragraph (e)(1) or (2) of this section.

(1) For a FCCU or FCU with no post-combustion control device:

(i) The hourly average temperature of the exhaust gases exiting the FCCU or FCU must not fall below the level established during the most recent performance test.

(ii) The hourly average oxygen (O_2) concentration of the exhaust gases exiting the FCCU or FCU must not fall below the level established during the most recent performance test.

(2) For a FCCU or FCU with a post-combustion control device:

(i) The hourly average temperature of the exhaust gas vent stream exiting the control device must not fall below the level established during the most recent performance test.

(ii) The hourly average O_2 concentration of the exhaust gas vent stream exiting the control device must not fall below the level established during the most recent performance test.

(f) Except as provided in paragraph (f)(3) of this section, each owner or operator of an affected sulfur recovery plant shall comply with the applicable emission limits in paragraph (f)(1) or (2) of this section.

(1) For a sulfur recovery plant with a design production capacity greater than 20 long tons per day (LTD), the owner or operator shall comply with the applicable emission limit in paragraph (f)(1)(i) or (ii) of this section. If the sulfur recovery plant consists of multiple process trains or release points, the owner or operator shall comply with the applicable emission limit for each process train or release point individually or comply with the applicable emission limit in paragraph (f)(1)(i) or (ii) as a flow rate weighted average for a group of release points from the sulfur recovery plant provided that flow is monitored as specified in § 60.106a(a)(7); if flow is not monitored as specified in § 60.106a(a)(7), the owner or operator shall comply with the applicable emission limit in paragraph (f)(1)(i) or (ii) for each process train or release point individually. For a sulfur recovery plant with a design production capacity greater than 20 long LTD and a reduction control system not followed by incineration, the owner or operator shall also comply with the H_2S emission limit in paragraph (f)(1)(iii) of this section for each individual release point.

(i) For a sulfur recovery plant with an oxidation control system or a reduction control system followed by incineration, the owner or operator shall not discharge or cause the discharge of any gases containing SO_2 into the atmosphere in excess of the emission limit calculated using Equation 1 of this section. For Claus units that use only ambient air in the Claus burner or that elect not to monitor O_2 concentration of the air/oxygen mixture used in the Claus burner or for non-Claus sulfur recovery plants, this SO_2 emissions limit is 250 ppmv (dry basis) at zero percent excess air.

$$E_{LS} = k_1 \times \left(-0.038 \times (\%O_2)^2 + 11.53 \times \%O_2 + 25.6\right) \quad \text{(Eq. 1)}$$

Where:

E_{LS} = Emission limit for large sulfur recovery plant, ppmv (as SO_2, dry basis at zero percent excess air);

k_1 = Constant factor for emission limit conversion: k_1 = 1 for converting to the SO_2 limit for a sulfur recovery plant with an oxidation control system or a reduction control system followed by incineration and k_1 = 1.2 for converting to the reduced sulfur compounds limit for a sulfur recovery plant with a reduction control system not followed by incineration; and

$\%O_2$ = O_2 concentration of the air/oxygen mixture supplied to the Claus burner, percent by volume (dry basis). If only ambient air is used for the Claus burner or if the owner or operator elects not to monitor O_2 concentration of the air/oxygen mixture used in the Claus burner or for non-Claus sulfur recovery plants, use 20.9% for $\%O_2$.

(ii) For a sulfur recovery plant with a reduction control system not followed by incineration, the owner or operator shall not discharge or cause the discharge of any gases into the atmosphere containing reduced sulfur compounds in excess of the emission limit calculated using Equation 1 of this section. For Claus units that use only ambient air in the Claus burner or for non-Claus sulfur recovery plants, this reduced sulfur compounds emission limit is 300 ppmv calculated as ppmv SO_2 (dry basis) at 0-percent excess air.

(iii) For a sulfur recovery plant with a reduction control system not followed by incineration, the owner or operator shall not discharge or cause the discharge of any gases into the atmosphere containing hydrogen sulfide (H_2S) in excess of 10 ppmv calculated as ppmv SO_2 (dry basis) at zero percent excess air.

(2) For a sulfur recovery plant with a design production capacity of 20 LTD or less, the owner or operator shall comply with the applicable emission limit in paragraph (f)(2)(i) or (ii) of this section. If the sulfur recovery plant consists of multiple process trains or release points, the owner or operator may comply with the applicable emission limit for each process train or release point individually or comply with the applicable emission limit in paragraph (f)(2)(i) or (ii) as a flow rate weighted average for a group of release points from the sulfur recovery plant provided that flow is monitored as specified in § 60.106a(a)(7); if flow is not monitored as specified in § 60.106a(a)(7), the owner or operator shall comply with the applicable emission limit in paragraph (f)(2)(i) or (ii) for each process train or release point individually. For a sulfur recovery plant with a design production capacity of 20 LTD or less and a reduction control system not followed by incineration, the owner or operator shall also comply with the H_2S emission limit in paragraph (f)(2)(iii) of this section for each individual release point.

(i) For a sulfur recovery plant with an oxidation control system or a reduction control system followed by incineration, the owner or operator shall not discharge or cause the discharge of any gases into the atmosphere containing SO_2 in excess of the emission limit calculated using Equation 2 of this section. For Claus units that use only ambient air in the Claus burner or that elect not to monitor O_2 concentration of the air/oxygen mixture used in the Claus burner or for non-Claus sulfur recovery plants, this SO_2 emission limit is 2,500 ppmv (dry basis) at zero percent excess air.

$$E_{SS} = k_1 \times \left(-0.38 \times (\%O_2)^2 + 115.3 \times \%O_2 + 256\right) \qquad \text{(Eq. 2)}$$

Where:

E_{SS} = Emission limit for small sulfur recovery plant, ppmv (as SO_2, dry basis at zero percent excess air);

k_1 = Constant factor for emission limit conversion: k_1 = 1 for converting to the SO_2 limit for a sulfur recovery plant with an oxidation control system or a reduction control system followed by incineration and k_1 = 1.2 for converting to the reduced sulfur compounds limit for a sulfur recovery plant with a reduction control system not followed by incineration; and

$\%O_2$ = O_2 concentration of the air/oxygen mixture supplied to the Claus burner, percent by volume (dry basis). If only ambient air is used in the Claus burner or if the owner or operator elects not to monitor O_2 concentration of the air/oxygen mixture used in the Claus burner or for non-Claus sulfur recovery plants, use 20.9% for $\%O_2$.

(ii) For a sulfur recovery plant with a reduction control system not followed by incineration, the owner or operator shall not discharge or cause the discharge of any gases into the atmosphere containing reduced sulfur compounds in excess of the emission limit calculated using Equation 2 of this section. For Claus units that use only ambient air in the Claus burner or for non-Claus sulfur recovery plants, this reduced sulfur compounds emission limit is 3,000 ppmv calculated as ppmv SO_2 (dry basis) at zero percent excess air.

(iii) For a sulfur recovery plant with a reduction control system not followed by incineration, the owner or operator shall not discharge or cause the discharge of any gases into the atmosphere containing H_2S in excess of 100 ppmv calculated as ppmv SO_2 (dry basis) at zero percent excess air.

(3) The emission limits in paragraphs (f)(1) and (2) of this section shall not apply during periods of maintenance of the sulfur pit, which shall not exceed 240 hours per year. The owner or operator must document the time periods during which the sulfur pit vents were not controlled and measures taken to minimize emissions during these periods. Examples of these measures include not adding fresh sulfur or shutting off vent fans.

(g) Each owner or operator of an affected fuel gas combustion device shall comply with the emissions limits in paragraphs (g)(1) and (2) of this section.

(1) Except as provided in (g)(1)(iii) of this section, for each fuel gas combustion device, the owner or operator shall comply with either the emission limit in paragraph (g)(1)(i) of this section or the fuel gas concentration limit in paragraph (g)(1)(ii) of this section. For CO boilers or furnaces that are part of a fluid catalytic cracking unit or fluid coking unit affected facility, the owner or operator shall comply with the fuel gas concentration limit in paragraph (g)(1)(ii) for all fuel gas streams combusted in these units.

(i) The owner or operator shall not discharge or cause the discharge of any gases into the atmosphere that contain SO_2 in excess of 20 ppmv (dry basis, corrected to 0-percent excess air) determined hourly on a 3-hour rolling average basis and SO_2 in excess of 8 ppmv (dry basis, corrected to 0-percent excess air), determined daily on a 365 successive calendar day rolling average basis; or

(ii) The owner or operator shall not burn in any fuel gas combustion device any fuel gas that contains H_2S in excess of 162 ppmv determined hourly on a 3-hour rolling average basis and H_2S in excess of 60 ppmv determined daily on a 365 successive calendar day rolling average basis.

(iii) The combustion in a portable generator of fuel gas released as a result of tank degassing and/or cleaning is exempt from the emissions limits in paragraphs (g)(1)(i) and (ii) of this section.

(2) For each process heater with a rated capacity of greater than 40 million British thermal units per hour (MMBtu/hr) on a higher heating value basis, the owner or operator shall not discharge to the atmosphere any emissions of NO_X in excess of the applicable limits in paragraphs (g)(2)(i) through (iv) of this section.

(i) For each natural draft process heater, comply with the limit in either paragraph (g)(2)(i)(A) or (B) of this section. The owner or operator may comply with either limit at any time, provided that the appropriate parameters for each alternative are monitored as specified in § 60.107a; if fuel gas composition is not monitored as specified in § 60.107a(d), the owner or operator must comply with the concentration limits in paragraph (g)(2)(i)(A) of this section.

(A) 40 ppmv (dry basis, corrected to 0-percent excess air) determined daily on a 30-day rolling average basis; or

(B) 0.040 pounds per million British thermal units (lb/MMBtu) higher heating value basis determined daily on a 30-day rolling average basis.

(ii) For each forced draft process heater, comply with the limit in either paragraph (g)(2)(ii)(A) or (B) of this section. The owner or operator may comply with either limit at any time, provided that the appropriate parameters for each alternative are monitored as specified in § 60.107a; if fuel gas composition is not monitored as specified in § 60.107a(d), the owner or operator must comply with the concentration limits in paragraph (g)(2)(ii)(A) of this section.

(A) 60 ppmv (dry basis, corrected to 0-percent excess air) determined daily on a 30-day rolling average basis; or

(B) 0.060 lb/MMBtu higher heating value basis determined daily on a 30-day rolling average basis.

(iii) For each co-fired natural draft process heater, comply with the limit in either paragraph (g)(2)(iii)(A) or (B) of this section. The owner or operator must choose one of the emissions limits with which to comply at all times:

(A) 150 ppmv (dry basis, corrected to 0-percent excess air) determined daily on a 30 successive operating day rolling average basis; or

(B) The daily average emissions limit calculated using Equation 3 of this section:

$$ER_{NOx} = \frac{0.06\,Q_{gas}\,HHV_{gas} + 0.35\,Q_{oil}\,HHV_{oil}}{Q_{gas}\,HHV_{gas} + Q_{oil}\,HHV_{oil}} \quad \text{(Eq. 3)}$$

Where:

ER_{NOx} = Daily allowable average emission rate of NO_X, lb/MMBtu (higher heating value basis);

Q_{gas} = Daily average volumetric flow rate of fuel gas, standard cubic feet per day (scf/day);

Q_{oil} = Daily average volumetric flow rate of fuel oil, scf/day;

HHV_{gas} = Daily average higher heating value of gas fired to the process heater, MMBtu/scf; and

HHV_{oil} = Daily average higher heating value of fuel oil fired to the process heater, MMBtu/scf.

(iv) For each co-fired forced draft process heater, comply with the limit in either paragraph (g)(2)(iv)(A) or (B) of this section. The owner or operator must choose one of the emissions limits with which to comply at all times:

(A) 150 ppmv (dry basis, corrected to 0-percent excess air) determined daily on a 30 successive operating day rolling average basis; or

(B) The daily average emissions limit calculated using Equation 4 of this section:

$$ER_{NOx} = \frac{0.11\,Q_{gas}\,HHV_{gas} + 0.40\,Q_{oil}\,HHV_{oil}}{Q_{gas}\,HHV_{gas} + Q_{oil}\,HHV_{oil}} \quad \text{(Eq. 4)}$$

Where:

ER_{NOx} = Daily allowable average emission rate of NO_X, lb/MMBtu (higher heating value basis);

Q_{gas} = Daily average volumetric flow rate of fuel gas, scf/day;

Q_{oil} = Daily average volumetric flow rate of fuel oil, scf/day;

HHV_{gas} = Daily average higher heating value of gas fired to the process heater, MMBtu/scf; and

HHV_{oil} = Daily average higher heating value of fuel oil fired to the process heater, MMBtu/scf.

(h) [Reserved]

(i) For a process heater that meets any of the criteria of paragraphs (i)(1)(i) through (iv) of this section, an owner or operator may request approval from the Administrator for a NO_X emissions limit which shall apply specifically to that affected facility. The request shall include information as described in paragraph (i)(2) of this section. The request shall be submitted and followed as described in paragraph (i)(3) of this section.

(1) A process heater that meets one of the criteria in paragraphs (i)(1)(i) through (iv) of this section may apply for a site-specific NO_X emissions limit:

(i) A modified or reconstructed process heater that lacks sufficient space to accommodate installation and proper operation of combustion modification-based technology (e.g., ultra-low NO_X burners); or

(ii) A modified or reconstructed process heater that has downwardly firing induced draft burners; or

(iii) A co-fired process heater; or

(iv) A process heater operating at reduced firing conditions for an extended period of time (*i.e.*, operating in turndown mode). The site-specific NO_X emissions limit will only apply for those operating conditions.

(2) The request shall include sufficient and appropriate data, as determined by the Administrator, to allow the Administrator to confirm that the process heater is unable to comply with the applicable NO_X emissions limit in paragraph (g)(2) of this section. At a minimum, the request shall contain the information described in paragraphs (i)(2)(i) through (iv) of this section.

(i) The design and dimensions of the process heater, evaluation of available combustion modification-based technology, description of fuel gas and, if applicable, fuel oil characteristics, information regarding the combustion conditions (temperature, oxygen content, firing rates) and other information needed to demonstrate that the process heater meets one of the four classes of process heaters listed in paragraph (i)(1) of this section.

(ii) An explanation of how the data in paragraph (i)(2)(i) demonstrate that ultra-low NO_X burners, flue gas recirculation, control of excess air or other combustion modification-based technology (including combinations of these combustion modification-based technologies) cannot be used to meet the applicable emissions limit in paragraph (g)(2) of this section.

(iii) Results of a performance test conducted under representative conditions using the applicable methods specified in § 60.104a(i) to demonstrate the performance of the technology the owner or operator will use to minimize NO_X emissions.

(iv) The means by which the owner or operator will document continuous compliance with the site-specific emissions limit.

(3) The request shall be submitted and followed as described in paragraphs (i)(3)(i) through (iii) of this section.

(i) The owner or operator of a process heater that meets one of the criteria in paragraphs (i)(1)(i) through (iv) of this section may request approval from the Administrator within 180 days after initial startup of the process heater for a NO_X emissions limit which shall apply specifically to that affected facility.

(ii) The request must be submitted to the Administrator for approval. The owner or operator must comply with the request as submitted until it is approved.

(iii) The request shall also be submitted to the following address: U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Sector Policies and Programs Division, U.S. EPA Mailroom (E143–01), Attention: Refinery Sector Lead, 109 T.W. Alexander Drive, Research Triangle Park, NC 27711. Electronic copies in lieu of hard copies may also be submitted to *refinerynsps@epa.gov*.

(4) The approval process for a request for a facility-specific NO_X emissions limit is described in paragraphs (i)(4)(i) through (iii) of this section.

(i) Approval by the Administrator of a facility-specific NO_X emissions limit request will be based on the completeness, accuracy and reasonableness of the request. Factors that the EPA will consider in reviewing the request for approval include, but are not limited to, the following:

(A) A demonstration that the process heater meets one of the four classes of process heaters outlined in paragraphs (i)(1) of this section;

(B) A description of the low-NO_X burner designs and other combustion modifications considered for reducing NO_X emissions;

(C) The combustion modification option selected; and

(D) The operating conditions (firing rate, heater box temperature and excess oxygen concentration) at which the NO_X emission level was established.

(ii) If the request is approved by the Administrator, a facility-specific NO_X emissions limit will be established at the NO_X emission level demonstrated in the approved request.

(iii) If the Administrator finds any deficiencies in the request, the request must be revised to address the deficiencies and be re-submitted for approval.

[73 FR 35867, June 24, 2008, as amended at 77 FR 56466, Sep. 12, 2012; 80 FR 75230, Dec. 1, 2015; 81 FR 45240, July 13, 2016]

§ 60.103a Design, equipment, work practice or operational standards.

(a) Except as provided in paragraph (g) of this section, each owner or operator that operates a flare that is subject to this subpart shall develop and implement a written flare management plan no later than the date specified in paragraph (b) of this section. The flare management plan must include the information described in paragraphs (a)(1) through (7) of this section.

(1) A listing of all refinery process units, ancillary equipment, and fuel gas systems connected to the flare for each affected flare.

(2) An assessment of whether discharges to affected flares from these process units, ancillary equipment and fuel gas systems can be minimized. The flare minimization assessment must (at a minimum) consider the items in paragraphs (a)(2)(i) through (iv) of this section. The assessment must provide clear rationale in terms of costs (capital and annual operating), natural gas offset credits (if applicable), technical feasibility, secondary environmental impacts and safety considerations for the selected minimization alternative(s) or a statement, with justifications, that flow reduction could not be achieved. Based upon the assessment, each owner or operator of an affected flare shall identify the minimization alternatives that it has implemented by the due date of the flare management plan and shall include a schedule for the prompt implementation of any selected measures that cannot reasonably be completed as of that date.

(i) Elimination of process gas discharge to the flare through process operating changes or gas recovery at the source.

(ii) Reduction of the volume of process gas to the flare through process operating changes.

(iii) Installation of a flare gas recovery system or, for facilities that are fuel gas rich, a flare gas recovery system and a co-generation unit or combined heat and power unit.

(iv) Minimization of sweep gas flow rates and, for flares with water seals, purge gas flow rates.

(3) A description of each affected flare containing the information in paragraphs (a)(3)(i) through (vii) of this section.

(i) A general description of the flare, including the information in paragraphs (a)(3)(i)(A) through (G) of this section.

(A) Whether it is a ground flare or elevated (including height).

(B) The type of assist system (e.g., air, steam, pressure, non-assisted).

(C) Whether it is simple or complex flare tip (e.g., staged, sequential).

(D) Whether the flare is part of a cascaded flare system (and if so, whether the flare is primary or secondary).

(E) Whether the flare serves as a backup to another flare.

(F) Whether the flare is an emergency flare or a non-emergency flare.

(G) Whether the flare is equipped with a flare gas recovery system.

(ii) Description and simple process flow diagram showing the interconnection of the following components of the flare: flare tip (date installed, manufacturer, nominal and effective tip diameter, tip drawing); knockout or surge drum(s) or pot(s) (including dimensions and design capacities); flare header(s) and subheader(s); assist system; and ignition system.

(iii) Flare design parameters, including the maximum vent gas flow rate; minimum sweep gas flow rate; minimum purge gas flow rate (if any); maximum supplemental gas flow rate; maximum pilot gas flow rate; and, if the flare is steam-assisted, minimum total steam rate.

(iv) Description and simple process flow diagram showing all gas lines (including flare, purge (if applicable), sweep, supplemental and pilot gas) that are associated with the flare. For purge, sweep, supplemental and pilot gas, identify the type of gas used. Designate which lines are exempt from sulfur, H_2S or flow monitoring and why (e.g., natural gas, inherently low sulfur, pilot gas). Designate which lines are monitored and identify on the process flow diagram the location and type of each monitor.

(v) For each flow rate, H_2S, sulfur content, pressure or water seal monitor identified in paragraph (a)(3)(iv) of this section, provide a detailed description of the manufacturer's specifications, including, but not limited to, make, model, type, range, precision, accuracy, calibration, maintenance and quality assurance procedures.

(vi) For emergency flares, secondary flares and flares equipped with a flare gas recovery system designed, sized and operated to capture all flows except those resulting from startup, shutdown or malfunction:

(A) Description of the water seal, including the operating range for the liquid level.

(B) Designation of the monitoring option elected (flow and sulfur monitoring or pressure and water seal liquid level monitoring).

(vii) For flares equipped with a flare gas recovery system:

(A) A description of the flare gas recovery system, including number of compressors and capacity of each compressor.

(B) A description of the monitoring parameters used to quantify the amount of flare gas recovered.

(C) For systems with staged compressors, the maximum time period required to begin gas recovery with the secondary compressor(s), the monitoring parameters and procedures used to minimize the duration of releases during compressor staging and a justification for why the maximum time period cannot be further reduced.

(4) An evaluation of the baseline flow to the flare. The baseline flow to the flare must be determined after implementing the minimization assessment in paragraph (a)(2) of this section. Baseline flows do not include pilot gas flow or purge gas flow (*i.e.,* gas introduced after the flare's water seal) provided these gas flows remain reasonably constant (*i.e.,* separate flow monitors for these streams are not required). Separate baseline flow rates may be established for different operating conditions provided that the management plan includes:

(i) A primary baseline flow rate that will be used as the default baseline for all conditions except those specifically delineated in the plan;

(ii) A description of each special condition for which an alternate baseline is established, including the rationale for each alternate baseline, the daily flow for each alternate baseline and the expected duration of the special conditions for each alternate baseline; and

(iii) Procedures to minimize discharges to the affected flare during each special condition described in paragraph (a)(4)(ii) of this section, unless procedures are already developed for these cases under paragraph (a)(5) through (7) of this section, as applicable.

(5) Procedures to minimize or eliminate discharges to the flare during the planned startup and shutdown of the refinery process units and ancillary equipment that are connected to the affected flare, together with a schedule for the prompt implementation of any procedures that cannot reasonably be implemented as of the date of the submission of the flare management plan.

(6) Procedures to reduce flaring in cases of fuel gas imbalance (*i.e.,* excess fuel gas for the refinery's energy needs), together with a schedule for the prompt implementation of any procedures that cannot reasonably be implemented as of the date of the submission of the flare management plan.

(7) For flares equipped with flare gas recovery systems, procedures to minimize the frequency and duration of outages of the flare gas recovery system and procedures to minimize the volume of gas flared during such outages, together with a schedule for the prompt implementation of any procedures that cannot reasonably be implemented as of the date of the submission of the flare management plan.

(b) Except as provided in paragraph (g) of this section, each owner or operator required to develop and implement a written flare management plan as described in paragraph (a) of this section must submit the plan to the Administrator as described in paragraphs (b)(1) through (3) of this section.

(1) The owner or operator of a newly constructed or reconstructed flare must develop and implement the flare management plan by no later than the date that the flare becomes an affected facility subject to this subpart, except for the selected minimization alternatives in paragraph (a)(2) and/or the procedures in paragraphs (a)(5) though (a)(7) of this section that cannot reasonably be implemented by that date, which the owner or operator must implement in accordance with the schedule in the flare management plan. The owner or operator of a modified flare must develop and implement the flare management plan by no later than November 11, 2015 or upon startup of the modified flare, whichever is later.

(2) The owner or operator must comply with the plan as submitted by the date specified in paragraph (b)(1) of this section. The plan should be updated periodically to account for changes in the operation of the flare, such as new connections to the flare or the installation of a flare gas recovery system, but the plan need be re-submitted to the Administrator only if the owner or operator adds an alternative baseline flow rate, revises an existing baseline as described in paragraph (a)(4) of this section, installs a flare gas recovery system or is required to change flare designations and monitoring methods as described in § 60.107a(g). The owner or operator must comply with the updated plan as submitted.

(3) All versions of the plan submitted to the Administrator shall also be submitted to the following address: U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Sector Policies and Programs Division, U.S. EPA Mailroom (E143–01), Attention: Refinery Sector Lead, 109 T.W. Alexander Drive, Research Triangle Park, NC 27711. Electronic copies in lieu of hard copies may also be submitted to *refinerynsps@epa.gov*.

(c) Except as provided in paragraphs (f) and (g) of this section, each owner or operator that operates a fuel gas combustion device, flare or sulfur recovery plant subject to this subpart shall conduct a root cause analysis and a corrective action analysis for each of the conditions specified in paragraphs (c)(1) through (3) of this section.

(1) For a flare:

(i) Any time the SO_2 emissions exceed 227 kilograms (kg) (500 lb) in any 24-hour period; or

(ii) Any discharge to the flare in excess of 14,160 standard cubic meters (m^3) (500,000 standard cubic feet (scf)) above the baseline, determined in paragraph (a)(4) of this section, in any 24-hour period; or

(iii) If the monitoring alternative in § 60.107a(g) is elected, any period when the flare gas line pressure exceeds the water seal liquid depth, except for periods attributable to compressor staging that do not exceed the staging time specified in paragraph (a)(3)(vii)(C) of this section.

(2) For a fuel gas combustion device, each exceedance of an applicable short-term emissions limit in § 60.102a(g)(1) if the SO_2 discharge to the atmosphere is 227 kg (500 lb) greater than the amount that would have been emitted if the emissions limits had been met during one or more consecutive periods of excess emissions or any 24-hour period, whichever is shorter.

(3) For a sulfur recovery plant, each time the SO_2 emissions are more than 227 kg (500 lb) greater than the amount that would have been emitted if the SO_2 or reduced sulfur concentration was equal to the applicable emissions limit in § 60.102a(f)(1) or (2) during one or more consecutive periods of excess emissions or any 24-hour period, whichever is shorter.

(d) Except as provided in paragraphs (f) and (g) of this section, a root cause analysis and corrective action analysis must be completed as soon as possible, but no later than 45 days after a discharge meeting one of the conditions specified in paragraphs (c)(1) through (3) of this section. Special circumstances affecting the number of root cause analyses and/or corrective action analyses are provided in paragraphs (d)(1) through (5) of this section.

(1) If a single continuous discharge meets any of the conditions specified in paragraphs (c)(1) through (3) of this section for 2 or more consecutive 24-hour periods, a single root cause analysis and corrective action analysis may be conducted.

(2) If a single discharge from a flare triggers a root cause analysis based on more than one of the conditions specified in paragraphs (c)(1)(i) through (iii) of this section, a single root cause analysis and corrective action analysis may be conducted.

(3) If the discharge from a flare is the result of a planned startup or shutdown of a refinery process unit or ancillary equipment connected to the affected flare and the procedures in paragraph (a)(5) of this section were followed, a root cause analysis and corrective action analysis is not required; however, the discharge must be recorded as described in § 60.108a(c)(6) and reported as described in § 60.108a(d)(5).

(4) If both the primary and secondary flare in a cascaded flare system meet any of the conditions specified in paragraphs (c)(1)(i) through (iii) of this section in the same 24-hour period, a single root cause analysis and corrective action analysis may be conducted.

(5) Except as provided in paragraph (d)(4) of this section, if discharges occur that meet any of the conditions specified in paragraphs (c)(1) through (3) of this section for more than one affected facility in the same 24-hour period, initial root cause analyses shall be conducted for each affected facility. If the initial root cause analyses indicate that the discharges have the same root cause(s), the initial root cause analyses can be recorded as a single root cause analysis and a single corrective action analysis may be conducted.

(e) Except as provided in paragraphs (f) and (g) of this section, each owner or operator of a fuel gas combustion device, flare or sulfur recovery plant subject to this subpart shall implement the corrective action(s) identified in the corrective action analysis conducted pursuant to paragraph (d) of this section in accordance with the applicable requirements in paragraphs (e)(1) through (3) of this section.

(1) All corrective action(s) must be implemented within 45 days of the discharge for which the root cause and corrective action analyses were required or as soon thereafter as practicable. If an owner or operator concludes that corrective action should not be conducted, the owner or operator shall record and explain the basis for that conclusion no later than 45 days following the discharge as specified in § 60.108a(c)(6)(ix).

(2) For corrective actions that cannot be fully implemented within 45 days following the discharge for which the root cause and corrective action analyses were required, the owner or operator shall develop an implementation schedule to complete the corrective action(s) as soon as practicable.

(3) No later than 45 days following the discharge for which a root cause and corrective action analyses were required, the owner or operator shall record the corrective action(s) completed to date, and, for action(s) not already completed, a schedule for implementation, including proposed commencement and completion dates as specified in § 60.108a(c)(6)(x).

(f) Modified flares shall comply with the requirements of paragraphs (c) through (e) of this section by November 11, 2015 or at startup of the modified flare, whichever is later. Modified flares that were not affected facilities subject to subpart J of this part prior to becoming affected facilities under § 60.100a shall comply with the requirements of paragraph (h) of this section and the requirements of § 60.107a(a)(2) by November 11, 2015 or at startup of the modified flare, whichever is later. Modified flares that were affected facilities subject to subpart J of this part prior to becoming affected facilities under § 60.100a shall comply with the requirements of paragraph (h) of this section and the requirements of § 60.107a(a)(2) by November 13, 2012 or at startup of the modified flare, whichever is later, except that modified flares that have accepted applicability of subpart J under a federal consent decree shall comply with the subpart J requirements as specified in the consent decree, but shall comply with the requirements of paragraph (h) of this section and the requirements of § 60.107a(a)(2) by no later than November 11, 2015.

(g) An affected flare subject to this subpart located in the Bay Area Air Quality Management District (BAAQMD) may elect to comply with both BAAQMD Regulation 12, Rule 11 and BAAQMD Regulation 12, Rule 12 as an alternative to complying with the requirements of paragraphs (a) through (e) of this section. An affected flare subject to this subpart located in the South Coast Air Quality Management District (SCAQMD) may elect to comply with SCAQMD Rule 1118 as an alternative to complying with the requirements of paragraphs (a) through (e) of this section. The owner or operator of an affected flare must notify the Administrator that the flare is in compliance with BAAQMD Regulation 12, Rule 11 and BAAQMD Regulation 12, Rule 12 or SCAQMD Rule 1118. The owner or operator of an affected flare shall also submit the existing flare management plan to the following address: U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Sector Policies and Programs Division, U.S. EPA Mailroom (E143–01), Attention: Refinery Sector Lead, 109 T.W. Alexander Drive, Research Triangle Park, NC 27711. Electronic copies in lieu of hard copies may also be submitted to *refinerynsps@epa.gov*.

(h) Each owner or operator shall not burn in any affected flare any fuel gas that contains H_2S in excess of 162 ppmv determined hourly on a 3-hour rolling average basis. The combustion in a flare of process upset gases or fuel gas that is released to the flare as a result of relief valve leakage or other emergency malfunctions is exempt from this limit.

(i) Each owner or operator of a delayed coking unit shall depressure each coke drum to 5 lb per square inch gauge (psig) or less prior to discharging the coke drum steam exhaust to the atmosphere. Until the coke drum pressure reaches 5 psig, the coke drum steam exhaust must be managed in an enclosed blowdown system and the uncondensed vapor must either be recovered (e.g., sent to the delayed coking unit fractionators) or vented to the fuel gas system, a fuel gas combustion device or a flare.

(j) *Alternative means of emission limitation.*

(1) Each owner or operator subject to the provisions of this section may apply to the Administrator for a determination of equivalence for any means of emission limitation that achieves a reduction in emissions of a specified pollutant at least equivalent to the reduction in emissions of that pollutant achieved by the controls required in this section.

(2) Determination of equivalence to the design, equipment, work practice or operational requirements of this section will be evaluated by the following guidelines:

(i) Each owner or operator applying for a determination of equivalence shall be responsible for collecting and verifying test data to demonstrate the equivalence of the alternative means of emission limitation.

(ii) For each affected facility for which a determination of equivalence is requested, the emission reduction achieved by the design, equipment, work practice or operational requirements shall be demonstrated.

(iii) For each affected facility for which a determination of equivalence is requested, the emission reduction achieved by the alternative means of emission limitation shall be demonstrated.

(iv) Each owner or operator applying for a determination of equivalence to a work practice standard shall commit in writing to work practice(s) that provide for emission reductions equal to or greater than the emission reductions achieved by the required work practice.

(v) The Administrator will compare the demonstrated emission reduction for the alternative means of emission limitation to the demonstrated emission reduction for the design, equipment, work practice or operational requirements and, if applicable, will consider the commitment in paragraph (j)(2)(iv) of this section.

(vi) The Administrator may condition the approval of the alternative means of emission limitation on requirements that may be necessary to ensure operation and maintenance to achieve the same emissions reduction as the design, equipment, work practice or operational requirements.

(3) An owner or operator may offer a unique approach to demonstrate the equivalence of any equivalent means of emission limitation.

(4) Approval of the application for equivalence to the design, equipment, work practice or operational requirements of this section will be evaluated by the following guidelines:

(i) After a request for determination of equivalence is received, the Administrator will publish a notice in the FEDERAL REGISTER and provide the opportunity for public hearing if the Administrator judges that the request may be approved.

(ii) After notice and opportunity for public hearing, the Administrator will determine the equivalence of a means of emission limitation and will publish the determination in the FEDERAL REGISTER.

(iii) Any equivalent means of emission limitations approved under this section shall constitute a required work practice, equipment, design or operational standard within the meaning of section 111(h)(1) of the CAA.

(5) Manufacturers of equipment used to control emissions may apply to the Administrator for determination of equivalence for any alternative means of emission limitation that achieves a reduction in emissions achieved by the equipment, design and operational requirements of this section. The Administrator will make an equivalence determination according to the provisions of paragraphs (j)(2) through (4) of this section.

[77 FR 56467, Sep. 12, 2012]

§ 60.104a Performance tests.

(a) The owner or operator shall conduct a performance test for each FCCU, FCU, sulfur recovery plant and fuel gas combustion device to demonstrate initial compliance with each applicable emissions limit in § 60.102a and conduct a performance test for each flare to demonstrate initial compliance with the H_2S concentration requirement in § 60.103a(h) according to the requirements of § 60.8. The notification requirements of § 60.8(d) apply to the initial performance test and to subsequent performance tests required by paragraph (b) of this section (or as required by the Administrator), but does not apply to performance tests conducted for the purpose of obtaining supplemental data because of continuous monitoring system breakdowns, repairs, calibration checks and zero and span adjustments.

(b) The owner or operator of a FCCU or FCU that elects to monitor control device operating parameters according to the requirements in § 60.105a(b), to use bag leak detectors according to the requirements in § 60.105a(c), or to use COMS according to the requirements in § 60.105a(e) shall conduct a PM performance test at least annually (*i.e.*, once per calendar year, with an interval of at least 8 months but no more than 16 months between annual tests) and furnish the Administrator a written report of the results of each test.

(c) In conducting the performance tests required by this subpart (or as requested by the Administrator), the owner or operator shall use the test methods in 40 CFR part 60, Appendices A–1 through A–8 or other methods as specified in this section, except as provided in § 60.8(b).

(d) The owner or operator shall determine compliance with the PM, NO_X, SO_2, and CO emissions limits in § 60.102a(b) for FCCU and FCU using the following methods and procedures:

(1) Method 1 of appendix A–1 to part 60 for sample and velocity traverses.

(2) Method 2 of appendix A–1 to part 60 for velocity and volumetric flow rate.

(3) Method 3, 3A, or 3B of appendix A–2 to part 60 for gas analysis. The method ANSI/ASME PTC 19.10–1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 3B of appendix A–2 to part 60.

(4) Method 5, 5B, or 5F of appendix A–3 to part 60 for determining PM emissions and associated moisture content from a FCCU or FCU without a wet scrubber subject to the emissions limit in § 63.102a(b)(1). Use Method 5 or 5B of appendix A–3 to part 60 for determining PM emissions and associated moisture content from a FCCU or FCU with a wet scrubber subject to the emissions limit in § 63.102a(b)(1).

(i) The PM performance test consists of 3 valid test runs; the duration of each test run must be no less than 60 minutes.

(ii) The emissions rate of PM (E_{PM}) is computed for each run using Equation 5 of this section:

$$E = \frac{c_s Q_{sd}}{K R_c} \qquad \text{(Eq. 5)}$$

Where:

E = Emission rate of PM, g/kg (lb/1,000 lb) of coke burn-off;

c_s = Concentration of total PM, grams per dry standard cubic meter (g/dscm) (gr/dscf);

Q_{sd} = Volumetric flow rate of effluent gas, dry standard cubic meters per hour (dry standard cubic feet per hour);

R_c = Coke burn-off rate, kilograms per hour (kg/hr) [lb per hour (lb/hr)] coke; and

K = Conversion factor, 1.0 grams per gram (7,000 grains per lb).

(iii) The coke burn-off rate (R_c) is computed for each run using Equation 6 of this section:

$$R_c = K_1 Q_r (\%CO_2 + \%CO) + K_2 Q_a - K_3 Q_r \left(\frac{\%CO}{2} + \%CO_2 + \%O_2\right) + K_3 Q_{oxy} (\%O_{oxy}) \qquad \text{(Eq. 6)}$$

Where:

R_c = Coke burn-off rate, kg/hr (lb/hr);

Q_r = Volumetric flow rate of exhaust gas from FCCU regenerator or fluid coking burner before any emissions control or energy recovery system that burns auxiliary fuel, dry standard cubic meters per minute (dscm/min) [dry standard cubic feet per minute (dscf/min)];

Q_a = Volumetric flow rate of air to FCCU regenerator or fluid coking burner, as determined from the unit's control room instrumentation, dscm/min (dscf/min);

Q_{oxy} = Volumetric flow rate of O_2 enriched air to FCCU regenerator or fluid coking unit, as determined from the unit's control room instrumentation, dscm/min (dscf/min);

$\%CO_2$ = Carbon dioxide (CO_2) concentration in FCCU regenerator or fluid coking burner exhaust, percent by volume (dry basis);

%CO = CO concentration in FCCU regenerator or fluid coking burner exhaust, percent by volume (dry basis);

$\%O_2$ = O_2 concentration in FCCU regenerator or fluid coking burner exhaust, percent by volume (dry basis);

$\%O_{oxy}$ = O_2 concentration in O_2 enriched air stream inlet to the FCCU regenerator or fluid coking burner, percent by volume (dry basis);

K_1 = Material balance and conversion factor, 0.2982 (kg-min)/(hr-dscm-%) [0.0186 (lb-min)/(hr-dscf-%)];

K_2 = Material balance and conversion factor, 2.088 (kg-min)/(hr-dscm) [0.1303 (lb-min)/(hr-dscf)]; and

K_3 = Material balance and conversion factor, 0.0994 (kg-min)/(hr-dscm-%) [0.00624 (lb-min)/(hr-dscf-%)].

(iv) During the performance test, the volumetric flow rate of exhaust gas from catalyst regenerator (Q_r) before any emission control or energy recovery system that burns auxiliary fuel is measured using Method 2 of appendix A–1 to part 60.

(v) For subsequent calculations of coke burn-off rates or exhaust gas flow rates, the volumetric flow rate of Q_r is calculated using average exhaust gas concentrations as measured by the monitors required in § 60.105a(b)(2), if applicable, using Equation 7 of this section:

$$Q_r = \frac{79 \times Q_a + (100 - \%Oxy) \times Q_{oxy}}{100 - \%CO_2 - \%CO - \%O_2} \qquad \text{(Eq. 7)}$$

Where:

Q_r = Volumetric flow rate of exhaust gas from FCCU regenerator or fluid coking burner before any emission control or energy recovery system that burns auxiliary fuel, dscm/min (dscf/min);

Q_a = Volumetric flow rate of air to FCCU regenerator or fluid coking burner, as determined from the unit's control room instrumentation, dscm/min (dscf/min);

Q_{oxy} = Volumetric flow rate of O_2 enriched air to FCCU regenerator or fluid coking unit, as determined from the unit's control room instrumentation, dscm/min (dscf/min);

$\%CO_2$ = Carbon dioxide concentration in FCCU regenerator or fluid coking burner exhaust, percent by volume (dry basis);

%CO = CO concentration FCCU regenerator or fluid coking burner exhaust, percent by volume (dry basis). When no auxiliary fuel is burned and a continuous CO monitor is not required in accordance with § 60.105a(h)(3), assume %CO to be zero;

$\%O_2$ = O_2 concentration in FCCU regenerator or fluid coking burner exhaust, percent by volume (dry basis); and

$\%O_{oxy}$ = O_2 concentration in O_2 enriched air stream inlet to the FCCU regenerator or fluid coking burner, percent by volume (dry basis).

(5) Method 6, 6A, or 6C of appendix A–4 to part 60 for moisture content and for the concentration of SO_2; the duration of each test run must be no less than 4 hours. The method ANSI/ASME PTC 19.10–1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 6 or 6A of appendix A–4 to part 60.

(6) Method 7, 7A, 7C, 7D, or 7E of appendix A–4 to part 60 for moisture content and for the concentration of NO_X calculated as nitrogen dioxide (NO_2); the duration of each test run must be no less than 4 hours. The method ANSI/ASME PTC 19.10–1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 7 or 7C of appendix A–4 to part 60.

(7) Method 10, 10A, or 10B of appendix A–4 to part 60 for moisture content and for the concentration of CO. The sampling time for each run must be 60 minutes.

(8) The owner or operator shall adjust PM, NO_X, SO_2 and CO pollutant concentrations to 0-percent excess air or 0-percent O_2 using Equation 8 of this section:

$$C_{adj} = C_{meas}\left[20.9_c / (20.9 - \%O_2)\right] \qquad \text{(Eq. 8)}$$

Where:

C_{adj} = pollutant concentration adjusted to 0-percent excess air or O_2, parts per million (ppm) or g/dscm;

C_{meas} = pollutant concentration measured on a dry basis, ppm or g/dscm;

20.9_c = 20.9 percent O_2–0.0 percent O_2 (defined O_2 correction basis), percent;

20.9 = O_2 concentration in air, percent; and

$\%O_2$ = O_2 concentration measured on a dry basis, percent.

(e) The owner or operator of a FCCU or FCU that is controlled by an electrostatic precipitator or wet scrubber and that is subject to control device operating parameter limits in § 60.102a(c) shall establish the limits based on the performance test results according to the following procedures:

(1) Reduce the parameter monitoring data to hourly averages for each test run;

(2) Determine the hourly average operating limit for each required parameter as the average of the three test runs.

(f) The owner or operator of an FCCU or FCU that uses cyclones to comply with the PM per coke burn-off emissions limit in § 60.102a(b)(1) shall establish a site-specific opacity operating limit according to the procedures in paragraphs (f)(1) through (3) of this section.

(1) Collect COMS data every 10 seconds during the entire period of the PM performance test and reduce the data to 6-minute averages.

(2) Determine and record the hourly average opacity from all the 6-minute averages.

(3) Compute the site-specific limit using Equation 9 of this section:

$$Opacity\ \ Limit = Opacity_{st}\ x\left(\frac{1\,\text{lb} / 1{,}000\ \text{lb coke burn}}{PMEmR_{st}}\right) \quad \text{(Eq. 9)}$$

Where:

Opacity limit = Maximum permissible 3-hour average opacity, percent, or 10 percent, whichever is greater;

$Opacity_{st}$ = Hourly average opacity measured during the source test, percent; and

$PMEmR_{st}$ = PM emission rate measured during the source test, lb/1,000 lb coke burn.

(g) The owner or operator of a FCCU or FCU that is exempt from the requirement to install and operate a CO CEMS pursuant to § 60.105a(h)(3) and that is subject to control device operating parameter limits in § 60.102a(c) shall establish the limits based on the performance test results using the procedures in paragraphs (g)(1) and (2) of this section.

(1) Reduce the temperature and O_2 concentrations from the parameter monitoring systems to hourly averages for each test run.

(2) Determine the operating limit for temperature and O_2 concentrations as the average of the average temperature and O_2 concentration for the three test runs.

(h) The owner or operator shall determine compliance with the SO_2 emissions limits for sulfur recovery plants in § 60.102a(f)(1)(i) and (f)(2)(i) and the reduced sulfur compounds and H_2S emissions limits for sulfur recovery plants in § 60.102a(f)(1)(ii), (f)(1)(iii), (f)(2)(ii), and (f)(2)(iii) using the following methods and procedures:

(1) Method 1 of appendix A–1 to part 60 for sample and velocity traverses.

(2) Method 2 of appendix A–1 to part 60 for velocity and volumetric flow rate.

(3) Method 3, 3A, or 3B of appendix A–2 to part 60 for gas analysis. The method ANSI/ASME PTC 19.10–1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 3B of appendix A–2 to part 60.

(4) Method 6, 6A, or 6C of appendix A–4 to part 60 to determine the SO_2 concentration. The method ANSI/ASME PTC 19.10–1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 6 or 6A of appendix A–4 to part 60.

(5) Method 15 or 15A of appendix A–5 to part 60 or Method 16 of appendix A–6 to part 60 to determine the reduced sulfur compounds and H_2S concentrations. The method ANSI/ASME PTC 19.10–1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 15A of appendix A–5 to part 60.

(i) Each run consists of 16 samples taken over a minimum of 3 hours.

(ii) The owner or operator shall calculate the average H_2S concentration after correcting for moisture and O_2 as the arithmetic average of the H_2S concentration for each sample during the run (ppmv, dry basis, corrected to 0 percent excess air).

(iii) The owner or operator shall calculate the SO_2 equivalent for each run after correcting for moisture and O_2 as the arithmetic average of the SO_2 equivalent of reduced sulfur compounds for each sample during the run (ppmv, dry basis, corrected to 0 percent excess air).

(iv) The owner or operator shall use Equation 8 of this section to adjust pollutant concentrations to 0-percent O_2 or 0- percent excess air.

(6) If oxygen or oxygen-enriched air is used in the Claus burner and either Equation 1 or 2 of this subpart is used to determine the applicable emissions limit, determine the average O_2 concentration of the air/oxygen mixture supplied to the Claus burner, in percent by volume (dry basis), for the performance test using all hourly average O_2 concentrations determined during the test runs using the procedures in § 60.106a(a)(5) or (6).

(i) The owner or operator shall determine compliance with the SO_2 and NO_X emissions limits in § 60.102a(g) for a fuel gas combustion device according to the following test methods and procedures:

(1) Method 1 of appendix A–1 to part 60 for sample and velocity traverses;

(2) Method 2 of appendix A–1 to part 60 for velocity and volumetric flow rate;

(3) Method 3, 3A, or 3B of appendix A–2 to part 60 for gas analysis. The method ANSI/ASME PTC 19.10–1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 3B of appendix A–2 to part 60;

(4) Method 6, 6A, or 6C of appendix A–4 to part 60 to determine the SO_2 concentration. The method ANSI/ASME PTC 19.10–1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 6 or 6A of appendix A–4 to part 60.

(i) The performance test consists of 3 valid test runs; the duration of each test run must be no less than 1 hour.

(ii) If a single fuel gas combustion device having a common source of fuel gas is monitored as allowed under § 60.107a(a)(1)(v), only one performance test is required. That is, performance tests are not required when a new affected fuel gas combustion device is added to a common source of fuel gas that previously demonstrated compliance.

(5) Method 7, 7A, 7C, 7D, or 7E of appendix A–4 to part 60 for moisture content and for the concentration of NO_X calculated as NO_2; the duration of each test run must be no less than 4 hours. The method ANSI/ASME PTC 19.10–1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 7 or 7C of appendix A–4 to part 60.

(6) For process heaters with a rated heat capacity between 40 and 100 MMBtu/hr that elect to demonstrate continuous compliance with a maximum excess oxygen limit as provided in § 60.107a(c)(6) or (d)(8), the owner or operator shall establish the O_2 operating limit or O_2 operating curve based on the performance test results according to the requirements in paragraph (i)(6)(i) or (ii) of this section, respectively.

(i) If a single O_2 operating limit will be used:

(A) Conduct the performance test following the methods provided in paragraphs (i)(1), (2), (3) and (5) of this section when the process heater is firing at no less than 70 percent of the rated heat capacity. For co-fired process heaters, conduct at least one of the test runs while the process heater is being supplied by both fuel gas and fuel oil and conduct at least one of the test runs while the process heater is being supplied solely by fuel gas.

(B) Each test will consist of three test runs. Calculate the NO_X concentration for the performance test as the average of the NO_X concentrations from each of the three test runs. If the NO_X concentration for the performance test is less than or equal to the numerical value of the applicable NO_X emissions limit (regardless of averaging time), then the test is considered to be a valid test.

(C) Determine the average O_2 concentration for each test run of a valid test.

(D) Calculate the O_2 operating limit as the average O_2 concentration of the three test runs from a valid test.

(ii) If an O_2 operating curve will be used:

(A) Conduct a performance test following the methods provided in paragraphs (i)(1), (2), (3) and (5) of this section at a representative condition for each operating range for which different O_2 operating limits will be established. Different operating conditions may be defined as different firing rates (e.g., above 50 percent of rated heat capacity and at or below 50 percent of rated heat capacity) and/or, for co-fired process heaters, different fuel mixtures (e.g., primarily gas fired, primarily oil fired, and equally co-fired, *i.e.,* approximately 50 percent of the input heating value is from fuel gas and approximately 50 percent of the input heating value is from fuel oil). Performance tests for different operating ranges may be conducted at different times.

(B) Each test will consist of three test runs. Calculate the NO_X concentration for the performance test as the average of the NO_X concentrations from each of the three test runs. If the NO_X concentration for the performance test is less than or equal to the numerical value of the applicable NO_X emissions limit (regardless of averaging time), then the test is considered to be a valid test.

(C) If an operating curve is developed for different firing rates, conduct at least one test when the process heater is firing at no less than 70 percent of the rated heat capacity and at least one test under turndown conditions (*i.e.,* when the process heater is firing at 50 percent or less of the rated heat capacity). If O_2 operating limits are developed for co-fired process heaters based only on overall firing rates (and not by fuel mixtures), conduct at least one of the test runs for each test while the process heater is being supplied by both fuel gas and fuel oil and conduct at least one of the test runs while the process heater is being supplied solely by fuel gas.

(D) Determine the average O_2 concentration for each test run of a valid test.

(E) Calculate the O_2 operating limit for each operating range as the average O_2 concentration of the three test runs from a valid test conducted at the representative conditions for that given operating range.

(F) Identify the firing rates for which the different operating limits apply. If only two operating limits are established based on firing rates, the O_2 operating limits established when the process heater is firing at no less than 70 percent of the rated heat capacity must apply when the process heater is firing above 50 percent of the rated heat capacity and the O_2 operating limits established for turndown conditions must apply when the process heater is firing at 50 percent or less of the rated heat capacity.

(G) Operating limits associated with each interval will be valid for 2 years or until another operating limit is established for that interval based on a more recent performance test specific for that interval, whichever occurs first. Owners and operators must use the operating limits determined for a given interval based on the most recent performance test conducted for that interval.

(7) The owner or operator of a process heater complying with a NO_X limit in terms of lb/MMBtu as provided in § 60.102a(g)(2)(i)(B), (g)(2)(ii)(B), (g)(2)(iii)(B) or (g)(2)(iv)(B) or a process heater with a rated heat capacity between 40 and 100 MMBtu/hr that elects to demonstrate continuous compliance with a maximum excess O_2 limit, as provided in § 60.107a(c)(6) or (d)(8), shall determine heat input to the process heater in MMBtu/hr during each performance test run by measuring fuel gas flow rate, fuel oil flow rate (as applicable) and heating value content according to the methods provided in § 60.107a(d)(5), (d)(6), and (d)(4) or (d)(7), respectively.

(8) The owner or operator shall use Equation 8 of this section to adjust pollutant concentrations to 0-percent O_2 or 0- percent excess air.

(j) The owner or operator shall determine compliance with the applicable H_2S emissions limit in § 60.102a(g)(1) for a fuel gas combustion device or the concentration requirement in § 60.103a(h) for a flare according to the following test methods and procedures:

(1)—(3) [Reserved]

(4) EPA Method 11, 15 or 15A of appendix A–5 to part 60 or EPA Method 16 of appendix A–6 to part 60 for determining the H_2S concentration for affected facilities using an H_2S monitor as specified in § 60.107a(a)(2). The method ANSI/ASME PTC 19.10–1981 (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 15A of appendix A–5 to part 60. The owner or operator may demonstrate compliance based on the mixture used in the fuel gas combustion device or flare or for each individual fuel gas stream used in the fuel gas combustion device or flare.

(i) For Method 11 of appendix A–5 to part 60, the sampling time and sample volume must be at least 10 minutes and 0.010 dscm (0.35 dscf). Two samples of equal sampling times must be taken at about 1-hour intervals. The arithmetic average of these two samples constitutes a run. For most fuel gases, sampling times exceeding 20 minutes may result in depletion of the collection solution, although fuel gases containing low concentrations of H_2S may necessitate sampling for longer periods of time.

(ii) For Method 15 of appendix A–5 to part 60, at least three injects over a 1-hour period constitutes a run.

(iii) For Method 15A of appendix A–5 to part 60, a 1-hour sample constitutes a run. The method ANSI/ASME PTC 19.10–1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 15A of appendix A–5 to part 60.

(iv) If monitoring is conducted at a single point in a common source of fuel gas as allowed under § 60.107a(a)(2)(iv), only one performance test is required. That is, performance tests are not required when a new affected fuel gas combustion device or flare is added to a common source of fuel gas that previously demonstrated compliance.

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§ 60.105a Monitoring of emissions and operations for fluid catalytic cracking units (FCCU) and fluid coking units (FCU).

(a) ***FCCU and FCU subject to PM emissions limit.*** Each owner or operator subject to the provisions of this subpart shall monitor each FCCU and FCU subject to the PM emissions limit in § 60.102a(b)(1) according to the requirements in paragraph (b), (c), (d), or (e) of this section.

(b) ***Control device operating parameters.*** Each owner or operator of a FCCU or FCU subject to the PM per coke burn-off emissions limit in § 60.102a(b)(1) that uses a control device other than fabric filter or cyclone shall comply with the requirements in paragraphs (b)(1) and (2) of this section.

(1) The owner or operator shall install, operate and maintain continuous parameter monitor systems (CPMS) to measure and record operating parameters for each control device according to the applicable requirements in paragraphs (b)(1)(i) through (v) of this section.

(i) For units controlled using an electrostatic precipitator, the owner or operator shall use CPMS to measure and record the hourly average total power input and secondary current to the entire system.

(ii) For units controlled using a wet scrubber, the owner or operator shall use CPMS to measure and record the hourly average pressure drop, liquid feed rate, and exhaust gas flow rate. As an alternative to a CPMS, the owner or operator must comply with the requirements in either paragraph (b)(1)(ii)(A) or (B) of this section.

(A) As an alternative to pressure drop, the owner or operator of a jet ejector type wet scrubber or other type of wet scrubber equipped with atomizing spray nozzles must conduct a daily check of the air or water pressure to the spray nozzles and record the results of each check. Faulty (*e.g.*, leaking or plugged) air or water lines must be repaired within 12 hours of identification of an abnormal pressure reading.

(B) As an alternative to exhaust gas flow rate, the owner or operator shall comply with the approved alternative for monitoring exhaust gas flow rate in 40 CFR 63.1573(a) of the National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units.

(iii) The owner or operator shall install, operate, and maintain each CPMS according to the manufacturer's specifications and requirements.

(iv) The owner or operator shall determine and record the average coke burn-off rate and hours of operation for each FCCU or FCU using the procedures in § 60.104a(d)(4)(iii).

(v) If you use a control device other than an electrostatic precipitator, wet scrubber, fabric filter, or cyclone, you may request approval to monitor parameters other than those required in paragraph (b)(1) of this section by submitting an alternative monitoring plan to the Administrator. The request must include the information in paragraphs (b)(1)(v)(A) through (E) of this section.

(A) A description of each affected facility and the parameter(s) to be monitored to determine whether the affected facility will continuously comply with the emission limitations and an explanation of the criteria used to select the parameter(s).

(B) A description of the methods and procedures that will be used to demonstrate that the parameter(s) can be used to determine whether the affected facility will continuously comply with the emission limitations and the schedule for this demonstration. The owner or operator must certify that an operating limit will be established for the monitored parameter(s) that represents the conditions in existence when the control device is being properly operated and maintained to meet the emission limitation.

(C) The frequency and content of the recordkeeping, recording, and reporting, if monitoring and recording are not continuous. The owner or operator also must include the rationale for the proposed monitoring, recording, and reporting requirements.

(D) Supporting calculations.

(E) Averaging time for the alternative operating parameter.

(2) For use in determining the coke burn-off rate for an FCCU or FCU, the owner or operator shall install, operate, calibrate, and maintain an instrument for continuously monitoring the concentrations of CO_2, O_2 (dry basis), and if needed, CO in the exhaust gases prior to any control or energy recovery system that burns auxiliary fuels. A CO monitor is not required for determining coke burn-off rate when no auxiliary fuel is burned and a continuous CO monitor is not required in accordance with paragraph (h)(3) of this section.

(i) The owner or operator shall install, operate, and maintain each CO_2 and O_2 monitor according to Performance Specification 3 of appendix B to this part.

(ii) The owner or operator shall conduct performance evaluations of each CO_2 and O_2 monitor according to the requirements in § 60.13(c) and Performance Specification 3 of appendix B to this part. The owner or operator shall use Method 3, 3A or 3B of appendix A–2 to this part for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10–1981, “Flue and Exhaust Gas Analyses,” (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 3B of appendix A–2 to part 60.

(iii) If a CO monitor is required, the owner or operator shall install, operate, and maintain each CO monitor according to Performance Specification 4 or 4A of appendix B to this part. If this CO monitor also serves to demonstrate compliance with the CO emissions limit in § 60.102a(b)(4), the span value for this instrument is 1,000 ppm; otherwise, the span value for this instrument should be set at approximately 2 times the typical CO concentration expected in the FCCU of FCU flue gas prior to any emission control or energy recovery system that burns auxiliary fuels.

(iv) If a CO monitor is required, the owner or operator shall conduct performance evaluations of each CO monitor according to the requirements in § 60.13(c) and Performance Specification 4 of appendix B to this part. The owner or operator shall use Method 10, 10A, or 10B of appendix A–3 to this part for conducting the relative accuracy evaluations.

(v) The owner or operator shall comply with the quality assurance requirements of procedure 1 of appendix F to this part, including quarterly accuracy determinations for CO_2 and CO monitors, annual accuracy determinations for O_2 monitors, and daily calibration drift tests.

(c) ***Bag leak detection systems.*** Each owner or operator shall install, operate, and maintain a bag leak detection system for each baghouse or similar fabric filter control device that is used to comply with the PM per coke burn-off emissions limit in § 60.102a(b)(1) for an FCCU or FCU according to paragraph (c)(1) of this section; prepare and operate by a site-specific monitoring plan according to paragraph (c)(2) of this section; take action according to paragraph (c)(3) of this section; and record information according to paragraph (c)(4) of this section.

(1) Each bag leak detection system must meet the specifications and requirements in paragraphs (c)(1)(i) through (viii) of this section.

(i) The bag leak detection system must be certified by the manufacturer to be capable of detecting PM emissions at concentrations of 0.00044 grains per actual cubic foot or less.

(ii) The bag leak detection system sensor must provide output of relative PM loadings. The owner or operator shall continuously record the output from the bag leak detection system using electronic or other means (e.g., using a strip chart recorder or a data logger).

(iii) The bag leak detection system must be equipped with an alarm system that will sound when the system detects an increase in relative particulate loading over the alarm set point established according to paragraph (c)(1)(iv) of this section, and the alarm must be located such that it can be heard by the appropriate plant personnel.

(iv) In the initial adjustment of the bag leak detection system, the owner or operator must establish, at a minimum, the baseline output by adjusting the sensitivity (range) and the averaging period of the device, the alarm set points, and the alarm delay time.

(v) Following initial adjustment, the owner or operator shall not adjust the averaging period, alarm set point, or alarm delay time without approval from the Administrator or delegated authority except as provided in paragraph (c)(1)(vi) of this section.

(vi) Once per quarter, the owner or operator may adjust the sensitivity of the bag leak detection system to account for seasonal effects, including temperature and humidity, according to the procedures identified in the site-specific monitoring plan required by paragraph (c)(2) of this section.

(vii) The owner or operator shall install the bag leak detection sensor downstream of the baghouse and upstream of any wet scrubber.

(viii) Where multiple detectors are required, the system's instrumentation and alarm may be shared among detectors.

(2) The owner or operator shall develop and submit to the Administrator for approval a site-specific monitoring plan for each baghouse and bag leak detection system. The owner or operator shall operate and maintain each baghouse and bag leak detection system according to the site-specific monitoring plan at all times. Each monitoring plan must describe the items in paragraphs (c)(2)(i) through (vii) of this section.

(i) Installation of the bag leak detection system;

(ii) Initial and periodic adjustment of the bag leak detection system, including how the alarm set-point will be established;

(iii) Operation of the bag leak detection system, including quality assurance procedures;

(iv) How the bag leak detection system will be maintained, including a routine maintenance schedule and spare parts inventory list;

(v) How the bag leak detection system output will be recorded and stored;

(vi) Procedures as specified in paragraph (c)(3) of this section. In approving the site-specific monitoring plan, the Administrator or delegated authority may allow owners and operators more than 3 hours to alleviate a specific condition that causes an alarm if the owner or operator identifies in the monitoring plan this specific condition as one that could lead to an alarm, adequately explains why it is not feasible to alleviate this condition within 3 hours of the time the alarm occurs, and demonstrates that the requested time will ensure alleviation of this condition as expeditiously as practicable; and

(vii) How the baghouse system will be operated and maintained, including monitoring of pressure drop across baghouse cells and frequency of visual inspections of the baghouse interior and baghouse components such as fans and dust removal and bag cleaning mechanisms.

(3) For each bag leak detection system, the owner or operator shall initiate procedures to determine the cause of every alarm within 1 hour of the alarm. Except as provided in paragraph (c)(2)(vi) of this section, the owner or operator shall alleviate the cause of the alarm within 3 hours of the alarm by taking whatever action(s) are necessary. Actions may include, but are not limited to the following:

(i) Inspecting the baghouse for air leaks, torn or broken bags or filter media, or any other condition that may cause an increase in particulate emissions;

(ii) Sealing off defective bags or filter media;

(iii) Replacing defective bags or filter media or otherwise repairing the control device;

(iv) Sealing off a defective baghouse compartment;

(v) Cleaning the bag leak detection system probe or otherwise repairing the bag leak detection system; or

(vi) Shutting down the process producing the particulate emissions.

(4) The owner or operator shall maintain records of the information specified in paragraphs (c)(4)(i) through (iii) of this section for each bag leak detection system.

(i) Records of the bag leak detection system output;

(ii) Records of bag leak detection system adjustments, including the date and time of the adjustment, the initial bag leak detection system settings, and the final bag leak detection system settings; and

(iii) The date and time of all bag leak detection system alarms, the time that procedures to determine the cause of the alarm were initiated, the cause of the alarm, an explanation of the actions taken, the date and time the cause of the alarm was alleviated, and whether the alarm was alleviated within 3 hours of the alarm.

(d) *Continuous emissions monitoring systems (CEMS).* An owner or operator subject to the PM concentration emission limit (in gr/dscf) in § 60.102a(b)(1) for an FCCU or FCU shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration (0 percent excess air) of PM in the exhaust gases prior to release to the atmosphere. The monitor must include an O_2 monitor for correcting the data for excess air.

(1) The owner or operator shall install, operate, and maintain each PM monitor according to Performance Specification 11 of appendix B to part 60. The span value of this PM monitor is 0.08 gr/dscf PM.

(2) The owner or operator shall conduct performance evaluations of each PM monitor according to the requirements in § 60.13(c) and Performance Specification 11 of appendix B to part 60. The owner or operator shall use EPA Methods 5 or 5I of appendix A–3 to part 60 or Method 17 of appendix A–6 to part 60 for conducting the relative accuracy evaluations.

(3) The owner or operator shall install, operate, and maintain each O_2 monitor according to Performance Specification 3 of appendix B to part 60. The span value of this O_2 monitor must be selected between 10 and 25 percent, inclusive.

(4) The owner or operator shall conduct performance evaluations of each O_2 monitor according to the requirements in § 60.13(c) and Performance Specification 3 of appendix B to part 60. Method 3, 3A, or 3B of appendix A–2 to part 60 shall be used for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10–1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 3B of appendix A–2 to part 60.

(5) The owner or operator shall comply with the quality assurance requirements of Procedure 2 of appendix B to part 60 for each PM CEMS and Procedure 1 of appendix F to part 60 for each O_2 monitor, including quarterly accuracy determinations for each PM monitor, annual accuracy determinations for each O_2 monitor, and daily calibration drift tests.

(e) *Alternative monitoring option for FCCU and FCU—COMS.* Each owner or operator of an FCCU or FCU that uses cyclones to comply with the PM emission limit in § 60.102a(b)(1) shall monitor the opacity of emissions according to the requirements in paragraphs (e)(1) through (3) of this section.

(1) The owner or operator shall install, operate, and maintain an instrument for continuously monitoring and recording the opacity of emissions from the FCCU or the FCU exhaust vent.

(2) The owner or operator shall install, operate, and maintain each COMS according to Performance Specification 1 of appendix B to part 60. The instrument shall be spanned at 20 to 60 percent opacity.

(3) The owner or operator shall conduct performance evaluations of each COMS according to § 60.13(c) and Performance Specification 1 of appendix B to part 60.

(f) ***FCCU and FCU subject to NO_X limit.*** Each owner or operator subject to the NO_X emissions limit in § 60.102a(b)(2) for an FCCU or FCU shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration by volume (dry basis, 0 percent excess air) of NO_X emissions into the atmosphere. The monitor must include an O_2 monitor for correcting the data for excess air.

(1) The owner or operator shall install, operate, and maintain each NO_X monitor according to Performance Specification 2 of appendix B to part 60. The span value of this NO_X monitor is 200 ppmv NO_X.

(2) The owner or operator shall conduct performance evaluations of each NO_X monitor according to the requirements in § 60.13(c) and Performance Specification 2 of appendix B to part 60. The owner or operator shall use Methods 7, 7A, 7C, 7D, or 7E of appendix A–4 to part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10–1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 7 or 7C of appendix A–4 to part 60.

(3) The owner or operator shall install, operate, and maintain each O_2 monitor according to Performance Specification 3 of appendix B to part 60. The span value of this O_2 monitor must be selected between 10 and 25 percent, inclusive.

(4) The owner or operator shall conduct performance evaluations of each O_2 monitor according to the requirements in § 60.13(c) and Performance Specification 3 of appendix B to part 60. Method 3, 3A, or 3B of appendix A–2 to part 60 shall be used for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10–1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 3B of appendix A–2 to part 60.

(5) The owner or operator shall comply with the quality assurance requirements of Procedure 1 of appendix F to part 60 for each NO_X and O_2 monitor, including quarterly accuracy determinations for NO_X monitors, annual accuracy determinations for O_2 monitors, and daily calibration drift tests.

(g) ***FCCU and FCU subject to SO_2 limit.*** The owner or operator subject to the SO_2 emissions limit in § 60.102a(b)(3) for an FCCU or an FCU shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration by volume (dry basis, corrected to 0 percent excess air) of SO_2 emissions into the atmosphere. The monitor shall include an O_2 monitor for correcting the data for excess air.

(1) The owner or operator shall install, operate, and maintain each SO_2 monitor according to Performance Specification 2 of appendix B to part 60. The span value of this SO_2 monitor is 200 ppmv SO_2.

(2) The owner or operator shall conduct performance evaluations of each SO_2 monitor according to the requirements in § 60.13(c) and Performance Specification 2 of appendix B to part 60. The owner or operator shall use Methods 6, 6A, or 6C of appendix A–4 to part 60 for conducting the relative accuracy evaluations. The method ANSI / ASME PTC 19.10–1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 6 or 6A of appendix A–4 to part 60.

(3) The owner or operator shall install, operate, and maintain each O_2 monitor according to Performance Specification 3 of appendix B to part 60. The span value of this O_2 monitor must be selected between 10 and 25 percent, inclusive.

(4) The owner or operator shall conduct performance evaluations of each O_2 monitor according to the requirements in § 60.13(c) and Performance Specification 3 of appendix B to part 60. Method 3, 3A, or 3B of appendix A–2 to part 60 shall be used for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10–1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 3B of appendix A–2 to part 60.

(5) The owner or operator shall comply with the quality assurance requirements in Procedure 1 of appendix F to part 60 for each SO_2 and O_2 monitor, including quarterly accuracy determinations for SO_2 monitors, annual accuracy determinations for O_2 monitors, and daily calibration drift tests.

(h) ***FCCU and fluid coking units subject to CO emissions limit.*** Except as specified in paragraph (h)(3) of this section, the owner or operator shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration by volume (dry basis) of CO emissions into the atmosphere from each FCCU and FCU subject to the CO emissions limit in § 60.102a(b)(4).

(1) The owner or operator shall install, operate, and maintain each CO monitor according to Performance Specification 4 or 4A of appendix B to this part. The span value for this instrument is 1,000 ppmv CO.

(2) The owner or operator shall conduct performance evaluations of each CO monitor according to the requirements in § 60.13(c) and Performance Specification 4 or 4A of appendix B to part 60. The owner or operator shall use Methods 10, 10A, or 10B of appendix A–4 to part 60 for conducting the relative accuracy evaluations.

(3) A CO CEMS need not be installed if the owner or operator demonstrates that all hourly average CO emissions are and will remain less than 50 ppmv (dry basis) corrected to 0 percent excess air. The Administrator may revoke this exemption from monitoring upon a determination that CO emissions on an hourly average basis have exceeded 50 ppmv (dry basis) corrected to 0 percent excess air, in which case a CO CEMS shall be installed within 180 days.

(i) The demonstration shall consist of continuously monitoring CO emissions for 30 days using an instrument that meets the requirements of Performance Specification 4 or 4A of appendix B to this part. The span value shall be 100 ppmv CO instead of 1,000 ppmv, and the relative accuracy limit shall be 10 percent of the average CO emissions or 5 ppmv CO, whichever is greater. For instruments that are identical to Method 10 of appendix A–4 to this part and employ the sample conditioning system of Method 10A of appendix A–4 to this part, the alternative relative accuracy test procedure in section 10.1 of Performance Specification 2 of appendix B to this part may be used in place of the relative accuracy test.

(ii) The owner or operator must submit the following information to the Administrator:

(A) The measurement data specified in paragraph (h)(3)(i) of this section along with all other operating data known to affect CO emissions; and

(B) Descriptions of the CPMS for exhaust gas temperature and O_2 monitor required in paragraph (h)(4) of this section and operating limits for those parameters to ensure combustion conditions remain similar to those that exist during the demonstration period.

(iii) The effective date of the exemption from installation and operation of a CO CEMS is the date of submission of the information and data required in paragraph (h)(3)(ii) of this section.

(4) The owner or operator of a FCCU or FCU that is exempted from the requirement to install and operate a CO CEMS in paragraph (h)(3) of this section shall install, operate, calibrate, and maintain CPMS to measure and record the operating parameters in paragraph (h)(4)(i) or (ii) of this section. The owner or operator shall install, operate, and maintain each CPMS according to the manufacturer's specifications.

(i) For a FCCU or FCU with no post-combustion control device, the temperature and O_2 concentration of the exhaust gas stream exiting the unit.

(ii) For a FCCU or FCU with a post-combustion control device, the temperature and O_2 concentration of the exhaust gas stream exiting the control device.

(i) *Excess emissions.* For the purpose of reports required by § 60.7(c), periods of excess emissions for a FCCU or FCU subject to the emissions limitations in § 60.102a(b) are defined as specified in paragraphs (i)(1) through (6) of this section. Note: Determine all averages, except for opacity, as the arithmetic average of the applicable 1-hour averages, e.g., determine the rolling 3-hour average as the arithmetic average of three contiguous 1-hour averages.

(1) If a CPMS is used according to paragraph (b)(1) of this section, all 3-hour periods during which the average PM control device operating characteristics, as measured by the continuous monitoring systems under paragraph (b)(1), fall below the levels established during the performance test. If the alternative to pressure drop CPMS is used for the owner or operator of a jet ejector type wet scrubber or other type of wet scrubber equipped with atomizing spray nozzles, each day in which abnormal pressure readings are not corrected within 12 hours of identification.

(2) If a bag leak detection system is used according to paragraph (c) of this section, each day in which the cause of an alarm is not alleviated within the time period specified in paragraph (c)(3) of this section.

(3) If a PM CEMS is used according to § 60.105a(d), all 7-day periods during which the average PM emission rate, as measured by the continuous PM monitoring system under § 60.105a(d) exceeds 0.040 gr/dscf corrected to 0 percent excess air for a modified or reconstructed FCCU, 0.020 gr/dscf corrected to 0 percent excess air for a newly constructed FCCU, or 0.040 gr/dscf for an affected fluid coking unit.

(4) If a COMS is used according to § 60.105a(e), all 3-hour periods during which the average opacity, as measured by the COMS under § 60.105a(e), exceeds the site-specific limit established during the most recent performance test.

(5) All rolling 7-day periods during which the average concentration of NO_X as measured by the NO_X CEMS under § 60.105a(f) exceeds 80 ppmv for an affected FCCU or FCU.

(6) All rolling 7-day periods during which the average concentration of SO_2 as measured by the SO_2 CEMS under § 60.105a(g) exceeds 50 ppmv, and all rolling 365-day periods during which the average concentration of SO_2 as measured by the SO_2 CEMS exceeds 25 ppmv.

(7) All 1-hour periods during which the average CO concentration as measured by the CO continuous monitoring system under paragraph (h) of this section exceeds 500 ppmv or, if applicable, all 1-hour periods during which the average temperature and O_2 concentration as measured by the continuous monitoring systems under paragraph (h)(4) of this section fall below the operating limits established during the performance test.

[73 FR 35867, June 24, 2008, as amended at 77 FR 56473, Sep. 12, 2012; 80 FR 75232, Dec. 1, 2015; 83 FR 60713, Nov. 26, 2018]

§ 60.106a Monitoring of emissions and operations for sulfur recovery plants.

(a) The owner or operator of a sulfur recovery plant that is subject to the emissions limits in § 60.102a(f)(1) or § 60.102a(f)(2) shall:

(1) For sulfur recovery plants subject to the SO_2 emission limit in § 60.102a(f)(1)(i) or § 60.102a(f)(2)(i), the owner or operator shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration (dry basis, zero percent excess air) of any SO_2 emissions into the atmosphere. The monitor shall include an oxygen monitor for correcting the data for excess air.

(i) The span value for the SO_2 monitor is two times the applicable SO_2 emission limit at the highest O_2 concentration in the air/oxygen stream used in the Claus burner, if applicable.

(ii) The owner or operator shall install, operate, and maintain each SO_2 CEMS according to Performance Specification 2 of appendix B to part 60.

(iii) The owner or operator shall conduct performance evaluations of each SO_2 monitor according to the requirements in § 60.13(c) and Performance Specification 2 of appendix B to part 60. The owner or operator shall use Method 6 or 6C of appendix A–4 to part 60. The method ANSI/ASME PTC 19.10–1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 6.

(iv) The owner or operator shall install, operate, and maintain each O_2 monitor according to Performance Specification 3 of appendix B to this part.

(v) The span value for the O_2 monitor must be selected between 10 and 25 percent, inclusive.

(vi) The owner or operator shall conduct performance evaluations for the O_2 monitor according to the requirements of § 60.13(c) and Performance Specification 3 of appendix B to this part. The owner or operator shall use Methods 3, 3A, or 3B of appendix A–2 to this part for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10–1981 (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 3B of appendix A–2 to this part.

(vii) The owner or operator shall comply with the applicable quality assurance procedures of appendix F to this part for each monitor, including annual accuracy determinations for each O_2 monitor, and daily calibration drift determinations.

(2) For sulfur recovery plants that are subject to the reduced sulfur compounds emission limit in § 60.102a(f)(1)(ii) or (f)(2)(ii), the owner or operator shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration of reduced sulfur compounds and O_2 emissions into the atmosphere. The reduced sulfur compounds emissions shall be calculated as SO_2 (dry basis, zero percent excess air).

(i) The span value for the reduced sulfur compounds monitor is two times the applicable reduced sulfur compounds emission limit as SO_2 at the highest O_2 concentration in the air/oxygen stream used in the Claus burner, if applicable.

(ii) The owner or operator shall install, operate, and maintain each reduced sulfur compounds CEMS according to Performance Specification 5 of appendix B to this part.

(iii) The owner or operator shall conduct performance evaluations of each reduced sulfur compounds monitor according to the requirements in § 60.13(c) and Performance Specification 5 of appendix B to this part. The owner or operator shall use Methods 15 or 15A of appendix A–5 to part 60 for conducting the relative accuracy evaluations. The method ANSI/ ASME PTC 19.10–1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 15A of appendix A–5 to part 60.

(iv) The owner or operator shall install, operate, and maintain each O_2 monitor according to Performance Specification 3 of appendix B to part 60.

(v) The span value for the O_2 monitor must be selected between 10 and 25 percent, inclusive.

(vi) The owner or operator shall conduct performance evaluations for the O_2 monitor according to the requirements of § 60.13(c) and Performance Specification 3 of appendix B to part 60. The owner or operator shall use Methods 3, 3A, or 3B of appendix A–2 to part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10–1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 3B of appendix A–2 to part 60.

(vii) The owner or operator shall comply with the applicable quality assurance procedures of appendix F to part 60 for each monitor, including annual accuracy determinations for each O_2 monitor, and daily calibration drift determinations.

(3) In place of the reduced sulfur compounds monitor required in paragraph (a)(2) of this section, the owner or operator may install, calibrate, operate, and maintain an instrument using an air or O_2 dilution and oxidation system to convert any reduced sulfur to SO_2 for continuously monitoring and recording the concentration (dry basis, 0 percent excess air) of the total resultant SO_2. The monitor must include an O_2 monitor for correcting the data for excess O_2.

(i) The span value for this monitor is two times the applicable reduced sulfur compounds emission limit as SO_2 at the highest O_2 concentration in the air/oxygen stream used in the Claus burner, if applicable.

(ii) The owner or operator shall conduct performance evaluations of each SO_2 monitor according to the requirements in § 60.13(c) and Performance Specification 5 of appendix B to part 60. The owner or operator shall use Methods 15 or 15A of appendix A–5 to part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10–1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 15A of appendix A–5 to part 60.

(iii) The owner or operator shall install, operate, and maintain each O_2 monitor according to Performance Specification 3 of appendix B to part 60.

(iv) The span value for the O_2 monitor must be selected between 10 and 25 percent, inclusive.

(v) The owner or operator shall conduct performance evaluations for the O_2 monitor according to the requirements of § 60.13(c) and Performance Specification 3 of appendix B to part 60. The owner or operator shall use Methods 3, 3A, or 3B of appendix A–2 to part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10–1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 3B of appendix A–2 to part 60.

(vi) The owner or operator shall comply with the applicable quality assurance procedures of appendix F to part 60 for each monitor, including quarterly accuracy determinations for each SO_2 monitor, annual accuracy determinations for each O_2 monitor, and daily calibration drift determinations.

(4) For sulfur recovery plants that are subject to the H_2S emission limit in § 60.102a(f)(1)(iii) or (f)(2)(iii), the owner or operator shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration of H_2S, and O_2 emissions into the atmosphere. The H_2S emissions shall be calculated as SO_2 (dry basis, zero percent excess air).

(i) The span value for this monitor is two times the applicable H_2S emission limit.

(ii) The owner or operator shall install, operate, and maintain each H_2S CEMS according to Performance Specification 7 of appendix B to this part.

(iii) The owner or operator shall conduct performance evaluations for each H_2S monitor according to the requirements of § 60.13(c) and Performance Specification 7 of appendix B to this part. The owner or operator shall use Methods 11 or 15 of appendix A–5 to this part or Method 16 of appendix A–6 to this part for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10–1981 (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 15A of appendix A–5 to this part.

(iv) The owner or operator shall install, operate, and maintain each O_2 monitor according to Performance Specification 3 of appendix B to this part.

(v) The span value for the O_2 monitor must be selected between 10 and 25 percent, inclusive.

(vi) The owner or operator shall conduct performance evaluations for the O_2 monitor according to the requirements of § 60.13(c) and Performance Specification 3 of appendix B to this part. The owner or operator shall use Methods 3, 3A, or 3B of appendix A–2 to this part for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10–1981 (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 3B of appendix A–2 to this part.

(vii) The owner or operator shall comply with the applicable quality assurance procedures of appendix F to this part for each monitor, including annual accuracy determinations for each O_2 monitor, and daily calibration drift determinations.

(5) For sulfur recovery plants that use oxygen or oxygen enriched air in the Claus burner and that elects to monitor O_2 concentration of the air/oxygen mixture supplied to the Claus burner, the owner or operator shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the O_2 concentration of the air/oxygen mixture supplied to the Claus burner in order to determine the allowable emissions limit.

(i) The owner or operator shall install, operate, and maintain each O_2 monitor according to Performance Specification 3 of appendix B to this part.

(ii) The span value for the O_2 monitor shall be 100 percent.

(iii) The owner or operator shall conduct performance evaluations for the O_2 monitor according to the requirements of § 60.13(c) and Performance Specification 3 of appendix B to this part. The owner or operator shall use Methods 3, 3A, or 3B of appendix A–2 to this part for conducting

$$ER = \frac{C_d \times 1.912 \times 10^{-3} \times Q \times T}{\text{KW-hour}} \qquad \text{(Eq. 7)}$$

Where:

ER = Emission rate in grams per KW-hour.

C_d = Measured NO_X concentration in ppm.

1.912×10^{-3} = Conversion constant for ppm NO_X to grams per standard cubic meter at 25 degrees Celsius.

Q = Stack gas volumetric flow rate, in standard cubic meter per hour.

T = Time of test run, in hours.

KW-hour = Brake work of the engine, in KW-hour.

(f) To determine compliance with the PM mass per unit output emission limitation, convert the concentration of PM in the engine exhaust using Equation 8 of this section:

$$ER = \frac{C_{adj} \times Q \times T}{\text{KW-hour}} \qquad \text{(Eq. 8)}$$

Where:

ER = Emission rate in grams per KW-hour.

C_{adj} = Calculated PM concentration in grams per standard cubic meter.

Q = Stack gas volumetric flow rate, in standard cubic meter per hour.

T = Time of test run, in hours.

KW-hour = Energy output of the engine, in KW.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37971, June 28, 2011]

NOTIFICATION, REPORTS, AND RECORDS FOR OWNERS AND OPERATORS

§ 60.4214 What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary CI internal combustion engine?

(a) Owners and operators of non-emergency stationary CI ICE that are greater than 2,237 KW (3,000 HP), or have a displacement of greater than or equal to 10 liters per cylinder, or are pre-2007 model year engines that are greater than 130 KW (175 HP) and not certified, must meet the requirements of paragraphs (a)(1) and (2) of this section.

(1) Submit an initial notification as required in § 60.7(a)(1). The notification must include the information in paragraphs (a)(1)(i) through (v) of this section.

(i) Name and address of the owner or operator;

(ii) The address of the affected source;

(iii) Engine information including make, model, engine family, serial number, model year, maximum engine power, and engine displacement;

(iv) Emission control equipment; and

(v) Fuel used.

(2) Keep records of the information in paragraphs (a)(2)(i) through (iv) of this section.

(i) All notifications submitted to comply with this subpart and all documentation supporting any notification.

(ii) Maintenance conducted on the engine.

(iii) If the stationary CI internal combustion is a certified engine, documentation from the manufacturer that the engine is certified to meet the emission standards.

(iv) If the stationary CI internal combustion is not a certified engine, documentation that the engine meets the emission standards.

(b) If the stationary CI internal combustion engine is an emergency stationary internal combustion engine, the owner or operator is not required to submit an initial notification. Starting with the model years in table 5 to this subpart, if the emergency engine does not meet the standards applicable to non-emergency engines in the applicable model year, the owner or operator must keep records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. The owner must record the time of operation of the engine and the reason the engine was in operation during that time.

(c) If the stationary CI internal combustion engine is equipped with a diesel particulate filter, the owner or operator must keep records of any corrective action taken after the backpressure monitor has notified the owner or operator that the high backpressure limit of the engine is approached.

(d) If you own or operate an emergency stationary CI ICE with a maximum engine power more than 100 HP that operates for the purpose specified in § 60.4211(f)(3)(i), you must submit an annual report according to the requirements in paragraphs (d)(1) through (3) of this section.

(1) The report must contain the following information:

(i) Company name and address where the engine is located.

(ii) Date of the report and beginning and ending dates of the reporting period.

(iii) Engine site rating and model year.

(iv) Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place.

(v)–(vi) [Reserved]

(vii) Hours spent for operation for the purposes specified in § 60.4211(f)(3)(i), including the date, start time, and end time for engine operation for the purposes specified in § 60.4211(f)(3)(i). The report must also identify the entity that dispatched the engine and the situation that necessitated the dispatch of the engine.

(2) The first annual report must cover the calendar year 2015 and must be submitted no later than March 31, 2016. Subsequent annual reports for each calendar year must be submitted no later than March 31 of the following calendar year.

(3) The annual report must be submitted electronically using the subpart specific reporting form in the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, the written report must be submitted to the Administrator at the appropriate address listed in § 60.4.

(e) Owners or operators of stationary CI ICE equipped with AECDs pursuant to the requirements of 40 CFR 1039.665 must report the use of AECDs as required by 40 CFR 1039.665(e).

[71 FR 39172, July 11, 2006, as amended at 78 FR 6696, Jan. 30, 2013; 81 FR 44219, July 7, 2016; 87 FR 48606, Aug. 10, 2022]

SPECIAL REQUIREMENTS

§ 60.4215 What requirements must I meet for engines used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands?

(a) Stationary CI ICE with a displacement of less than 30 liters per cylinder that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are required to meet the applicable emission standards in §§ 60.4202 and 60.4205.

(b) Stationary CI ICE that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are not required to meet the fuel requirements in § 60.4207.

(c) Stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are required to meet the following emission standards:

(1) For engines installed prior to January 1, 2012, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 17.0 g/KW-hr (12.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $45 \cdot n^{-0.2}$ g/KW-hr ($34 \cdot n^{-0.2}$ g/HP-hr) when maximum engine speed is 130 or more but less than 2,000 rpm, where n is maximum engine speed; and

(iii) 9.8 g/KW-hr (7.3 g/HP-hr) when maximum engine speed is 2,000 rpm or more.

(2) For engines installed on or after January 1, 2012, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 14.4 g/KW-hr (10.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $44 \cdot n^{-0.23}$ g/KW-hr ($33 \cdot n^{-0.23}$ g/HP-hr) when maximum engine speed is greater than or equal to 130 but less than 2,000 rpm and where n is maximum engine speed; and

(iii) 7.7 g/KW-hr (5.7 g/HP-hr) when maximum engine speed is greater than or equal to 2,000 rpm.

(3) Limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.40 g/KW-hr (0.30 g/HP-hr).

[71 FR 39172, July 11, 2006, as amended at 76 FR 37971, June 28, 2011]

§ 60.4216 What requirements must I meet for engines used in Alaska?

(a) Prior to December 1, 2010, owners and operators of stationary CI ICE with a displacement of less than 30 liters per cylinder located in areas of Alaska not accessible by the FAHS should refer to 40 CFR part 69 to determine the diesel fuel requirements applicable to such engines.

(b) Except as indicated in paragraph (c) of this section, manufacturers, owners and operators of stationary CI ICE with a displacement of less than 10 liters per cylinder located in remote areas of Alaska may meet the requirements of this subpart by manufacturing and installing engines meeting the Tier 2 or Tier 3 emission standards described in 40 CFR part 1042 for the same model year, displacement, and maximum engine power, as appropriate, rather than the otherwise applicable requirements of 40 CFR part 1039, as indicated in §§ 60.4201(f) and 60.4202(g).

(c) Manufacturers, owners, and operators of stationary CI ICE that are located in remote areas of Alaska may choose to meet the applicable emission standards for emergency engines in §§ 60.4202 and 60.4205, and not those for non-emergency engines in §§ 60.4201 and 60.4204, except that for 2014 model year and later nonemergency CI ICE, the owner or operator of any such engine must have that engine certified as meeting at least the Tier 3 PM standards identified in appendix I of 40 CFR part 1039 or in 40 CFR 1042.101.

(d) The provisions of § 60.4207 do not apply to owners and operators of pre-2014 model year stationary CI ICE subject to this subpart that are located in remote areas of Alaska.

(e) The provisions of § 60.4208(a) do not apply to owners and operators of stationary CI ICE subject to this subpart that are located in areas of Alaska not accessible by the FAHS until after December 31, 2009.

(f) The provisions of this section and § 60.4207 do not prevent owners and operators of stationary CI ICE subject to this subpart that are located in remote areas of Alaska from using fuels mixed with used lubricating oil, in volumes of up to 1.75 percent of the total fuel. The sulfur content of the used lubricating oil must be less than 200 parts per million. The used lubricating oil must meet the on-specification levels and properties for used oil in 40 CFR 279.11.

[76 FR 37971, June 28, 2011, as amended at 81 FR 44219, July 7, 2016; 86 FR 34359, June 29, 2021]

§ 60.4217 What emission standards must I meet if I am an owner or operator of a stationary internal combustion engine using special fuels?

Owners and operators of stationary CI ICE that do not use diesel fuel may petition the Administrator for approval of alternative emission standards, if they can demonstrate that they use a fuel that is not the fuel on which the manufacturer of the engine certified the engine and that the engine cannot meet the applicable standards required in § 60.4204 or § 60.4205 using such fuels and that use of such fuel is appropriate and reasonably necessary, considering cost, energy, technical feasibility, human health and environmental, and other factors, for the operation of the engine.

[76 FR 37972, June 28, 2011]

GENERAL PROVISIONS

§ 60.4218 What General Provisions and confidential information provisions apply to me?

(a) Table 8 to this subpart shows which parts of the General Provisions in §§ 60.1 through 60.19 apply to you.

(b) The provisions of 40 CFR 1068.10 and 1068.11 apply for engine manufacturers. For others, the general confidential business information (CBI) provisions apply as described in 40 CFR part 2.

[88 FR 4471, Jan. 24, 2023]

DEFINITIONS

§ 60.4219 What definitions apply to this subpart?

As used in this subpart, all terms not defined herein shall have the meaning given them in the CAA and in subpart A of this part.

Alaska Railbelt Grid means the service areas of the six regulated public utilities that extend from Fairbanks to Anchorage and the Kenai Peninsula. These utilities are Golden Valley Electric Association; Chugach Electric Association; Matanuska Electric Association; Homer Electric Association; Anchorage Municipal Light & Power; and the City of Seward Electric System.

Certified emissions life means the period during which the engine is designed to properly function in terms of reliability and fuel consumption, without being remanufactured, specified as a number of hours of operation or calendar years, whichever comes first. The values for certified emissions life for stationary CI ICE with a displacement of less than 10 liters per cylinder are given in 40 CFR 1039.101(g). The values for certified emissions life for stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder are given in 40 CFR 1042.101(e).

Combustion turbine means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), and any ancillary components and sub-components comprising any simple cycle combustion turbine, any regenerative/recuperative cycle combustion turbine, the combustion turbine portion of any cogeneration cycle combustion system, or the combustion turbine portion of any combined cycle steam/electric generating system.

Compression ignition means relating to a type of stationary internal combustion engine that is not a spark ignition engine.

Date of manufacture means one of the following things:

(1) For freshly manufactured engines and modified engines, date of manufacture means the date the engine is originally produced.

(2) For reconstructed engines, date of manufacture means the date the engine was originally produced, except as specified in paragraph (3) of this definition.

(3) Reconstructed engines are assigned a new date of manufacture if the fixed capital cost of the new and refurbished components exceeds 75 percent of the fixed capital cost of a comparable entirely new facility. An engine that is produced from a previously used engine block does not retain the date of manufacture of the engine in which the engine block was previously used if the engine is produced using all new components except for the engine block. In these cases, the date of manufacture is the date of reconstruction or the date the new engine is produced.

Diesel fuel means any liquid obtained from the distillation of petroleum with a boiling point of approximately 150 to 360 degrees Celsius. One commonly used form is number 2 distillate oil.

Diesel particulate filter means an emission control technology that reduces PM emissions by trapping the particles in a flow filter substrate and periodically removes the collected particles by either physical action or by oxidizing (burning off) the particles in a process called regeneration.

Emergency stationary internal combustion engine means any stationary reciprocating internal combustion engine that meets all of the criteria in paragraphs (1) through (3) of this definition. All emergency stationary ICE must comply with the requirements specified in § 60.4211(f) in order to be considered emergency stationary ICE. If the engine does not comply with the requirements specified in § 60.4211(f), then it is not considered to be an emergency stationary ICE under this subpart.

(1) The stationary ICE is operated to provide electrical power or mechanical work during an emergency situation. Examples include stationary ICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary ICE used to pump water in the case of fire or flood, etc.

(2) The stationary ICE is operated under limited circumstances for situations not included in paragraph (1) of this definition, as specified in § 60.4211(f).

(3) The stationary ICE operates as part of a financial arrangement with another entity in situations not included in paragraph (1) of this definition only as allowed in § 60.4211(f)(3)(i).

Engine manufacturer means the manufacturer of the engine. See the definition of "manufacturer" in this section.

Fire pump engine means an emergency stationary internal combustion engine certified to NFPA requirements that is used to provide power to pump water for fire suppression or protection.

Freshly manufactured engine means an engine that has not been placed into service. An engine becomes freshly manufactured when it is originally produced.

Installed means the engine is placed and secured at the location where it is intended to be operated.

Manufacturer has the meaning given in section 216(1) of the Act. In general, this term includes any person who manufactures a stationary engine for sale in the United States or otherwise introduces a new stationary engine into commerce in the United States. This includes importers who import stationary engines for sale or resale.

Maximum engine power means maximum engine power as defined in 40 CFR 1039.801.

Model year means the calendar year in which an engine is manufactured (see "date of manufacture"), except as follows:

(1) Model year means the annual new model production period of the engine manufacturer in which an engine is manufactured (see "date of manufacture"), if the annual new model production period is different than the calendar year and includes January 1 of the calendar year for which the model year is named. It may not begin before January 2 of the previous calendar year and it must end by December 31 of the named calendar year.

(2) For an engine that is converted to a stationary engine after being placed into service as a nonroad or other non-stationary engine, model year means the calendar year or new model production period in which the engine was manufactured (see "date of manufacture").

Other internal combustion engine means any internal combustion engine, except combustion turbines, which is not a reciprocating internal combustion engine or rotary internal combustion engine.

Reciprocating internal combustion engine means any internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work.

Remote areas of Alaska means areas of Alaska that meet either paragraph (1) or (2) of this definition.

(1) Areas of Alaska that are not accessible by the Federal Aid Highway System (FAHS).

(2) Areas of Alaska that meet all of the following criteria:

(i) The only connection to the FAHS is through the Alaska Marine Highway System, or the stationary CI ICE operation is within an isolated grid in Alaska that is not connected to the statewide electrical grid referred to as the Alaska Railbelt Grid.

(ii) At least 10 percent of the power generated by the stationary CI ICE on an annual basis is used for residential purposes.

(iii) The generating capacity of the source is less than 12 megawatts, or the stationary CI ICE is used exclusively for backup power for renewable energy.

Rotary internal combustion engine means any internal combustion engine which uses rotary motion to convert heat energy into mechanical work.

Spark ignition means relating to a gasoline, natural gas, or liquefied petroleum gas fueled engine or any other type of engine with a spark plug (or other sparking device) and with operating characteristics significantly similar to the theoretical Otto combustion cycle. Spark ignition engines usually use a throttle to regulate intake air flow to control power during normal operation. Dual-fuel engines in which a liquid fuel (typically diesel fuel) is used for CI and gaseous fuel (typically natural gas) is used as the primary fuel at an annual average ratio of less than 2 parts diesel fuel to 100 parts total fuel on an energy equivalent basis are spark ignition engines.

Stationary internal combustion engine means any internal combustion engine, except combustion turbines, that converts heat energy into mechanical work and is not mobile. Stationary ICE differ from mobile ICE in that a stationary internal combustion engine is not a nonroad engine as defined at 40 CFR 1068.30 (excluding paragraph (2)(ii) of that definition), and is not used to propel a motor vehicle, aircraft, or a vehicle used solely for competition. Stationary ICE include reciprocating ICE, rotary ICE, and other ICE, except combustion turbines.

Subpart means 40 CFR part 60, subpart IIII.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37972, June 28, 2011; 78 FR 6696, Jan. 30, 2013; 81 FR 44219, July 7, 2016; 86 FR 34360, June 29, 2021; 87 FR 48606, Aug. 10, 2022]

Table 1 to Subpart IIII of Part 60—Emission Standards for Stationary Pre-2007 Model Year Engines With a Displacement of <10 Liters per Cylinder and 2007–2010 Model Year Engines >2,237 KW (3,000 HP) and With a Displacement of <10 Liters per Cylinder

[As stated in §§ 60.4201(b), 60.4202(b), 60.4204(a), and 60.4205(a), you must comply with the following emission standards]

Maximum engine power	Emission standards for stationary pre-2007 model year engines with a displacement of <10 liters per cylinder and 2007–2010 model year engines >2,237 KW (3,000 HP) and with a displacement of <10 liters per cylinder in g/KW-hr (g/HP-hr)				
	NMHC + NO_X	HC	NO_X	CO	PM
KW<8 (HP<11)	10.5 (7.8)			8.0 (6.0)	1.0 (0.75)
8≤KW<19 (11≤HP<25)	9.5 (7.1)			6.6 (4.9)	0.80 (0.60)
19≤KW<37 (25≤HP<50)	9.5 (7.1)			5.5 (4.1)	0.80 (0.60)
37≤KW<56 (50≤HP<75)			9.2 (6.9)		
56≤KW<75 (75≤HP<100)			9.2 (6.9)		
75≤KW<130 (100≤HP<175)			9.2 (6.9)		
130≤KW<225 (175≤HP<300)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
225≤KW<450 (300≤HP<600)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
450≤KW≤560 (600≤HP≤750)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
KW>560 (HP>750)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)

Table 2 to Subpart IIII of Part 60—Emission Standards for 2008 Model Year and Later Emergency Stationary CI ICE <37 KW (50 HP) With a Displacement of <10 Liters per Cylinder

[As stated in § 60.4202(a)(1), you must comply with the following emission standards]

Engine power	Emission standards for 2008 model year and later emergency stationary CI ICE <37 KW (50 HP) with a displacement of <10 liters per cylinder in g/KW-hr (g/HP-hr)			
	Model year(s)	NO_X + NMHC	CO	PM
KW<8 (HP<11)	2008 +	7.5 (5.6)	8.0 (6.0)	0.40 (0.30)
8≤KW<19 (11≤HP<25)	2008 +	7.5 (5.6)	6.6 (4.9)	0.40 (0.30)

Engine power	Emission standards for 2008 model year and later emergency stationary CI ICE <37 KW (50 HP) with a displacement of <10 liters per cylinder in g/KW-hr (g/HP-hr)			
	Model year(s)	NO_X + NMHC	CO	PM
19≤KW<37 (25≤HP<50)	2008 +	7.5 (5.6)	5.5 (4.1)	0.30 (0.22)

Table 3 to Subpart IIII of Part 60—Certification Requirements for Stationary Fire Pump Engines

As stated in § 60.4202(d), you must certify new stationary fire pump engines beginning with the following model years:

Engine power	Starting model year engine manufacturers must certify new stationary fire pump engines according to § 60.4202(d)[1]
KW<75 (HP<100)	2011
75≤KW<130 (100≤HP<175)	2010
130≤KW≤560 (175≤HP≤750)	2009
KW>560 (HP>750)	2008

[1]Manufacturers of fire pump stationary CI ICE with a maximum engine power greater than or equal to 37 kW (50 HP) and less than 450 KW (600 HP) and a rated speed of greater than 2,650 revolutions per minute (rpm) are not required to certify such engines until three model years following the model year indicated in this Table 3 for engines in the applicable engine power category.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37972, June 28, 2011]

Table 4 to Subpart IIII of Part 60—Emission Standards for Stationary Fire Pump Engines

[As stated in §§ 60.4202(d) and 60.4205(c), you must comply with the following emission standards for stationary fire pump engines]

Maximum engine power	Model year(s)	NMHC + NO_X	CO	PM
KW<8 (HP<11)	2010 and earlier	10.5 (7.8)	8.0 (6.0)	1.0 (0.75)
	2011 +	7.5 (5.6)		0.40 (0.30)
8≤KW<19 (11≤HP<25)	2010 and earlier	9.5 (7.1)	6.6 (4.9)	0.80 (0.60)
	2011 +	7.5 (5.6)		0.40 (0.30)

Maximum engine power	Model year(s)	NMHC + NO_X	CO	PM
19≤KW<37 (25≤HP<50)	2010 and earlier	9.5 (7.1)	5.5 (4.1)	0.80 (0.60)
	2011 +	7.5 (5.6)		0.30 (0.22)
37≤KW<56 (50≤HP<75)	2010 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
	2011 +[1]	4.7 (3.5)		0.40 (0.30)
56≤KW<75 (75≤HP<100)	2010 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
	2011 +[1]	4.7 (3.5)		0.40 (0.30)
75≤KW<130 (100≤HP<175)	2009 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
	2010 +[2]	4.0 (3.0)		0.30 (0.22)
130≤KW<225 (175≤HP<300)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2009 +[3]	4.0 (3.0)		0.20 (0.15)
225≤KW<450 (300≤HP<600)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2009 +[3]	4.0 (3.0)		0.20 (0.15)
450≤KW≤560 (600≤HP≤750)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2009 +	4.0 (3.0)		0.20 (0.15)
KW>560 (HP>750)	2007 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2008 +	6.4 (4.8)		0.20 (0.15)

[1] For model years 2011–2013, manufacturers, owners and operators of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 revolutions per minute (rpm) may comply with the emission limitations for 2010 model year engines.

[2] For model years 2010–2012, manufacturers, owners and operators of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 rpm may comply with the emission limitations for 2009 model year engines.

[3] In model years 2009–2011, manufacturers of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 rpm may comply with the emission limitations for 2008 model year engines.

Table 5 to Subpart IIII of Part 60—Labeling and Recordkeeping Requirements for New Stationary Emergency Engines

[You must comply with the labeling requirements in § 60.4210(f) and the recordkeeping requirements in § 60.4214(b) for new emergency stationary CI ICE beginning in the following model years:]

Engine power	Starting model year
19≤KW<56 (25≤HP<75)	2013
56≤KW<130 (75≤HP<175)	2012
KW≥130 (HP≥175)	2011

Table 6 to Subpart IIII of Part 60—Optional 3-Mode Test Cycle for Stationary Fire Pump Engines

[As stated in § 60.4210(g), manufacturers of fire pump engines may use the following test cycle for testing fire pump engines:]

Mode No.	Engine speed[1]	Torque (percent)[2]	Weighting factors
1	Rated	100	0.30
2	Rated	75	0.50
3	Rated	50	0.20

[1] Engine speed: ±2 percent of point.

[2] Torque: NFPA certified nameplate HP for 100 percent point. All points should be ±2 percent of engine percent load value.

Table 7 to Subpart IIII of Part 60—Requirements for Performance Tests for Stationary CI ICE With a Displacement of ≥30 Liters per Cylinder

As stated in § 60.4213, you must comply with the following requirements for performance tests for stationary CI ICE with a displacement of ≥30 liters per cylinder:

Each	Complying with the requirement to	You must	Using	According to the following requirements
1. Stationary CI internal combustion engine with a displacement of ≥ 30 liters per cylinder	a. Reduce NO_X emissions by 90 percent or more;	i. Select the sampling port location and number/ location of traverse points at the inlet and outlet of the control device;		(a) For NO_X, O_2, and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line ('3-point long line'). If the duct is >12 inches in diameter *and* the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, appendix A–1, the duct may be sampled at '3-point long line'; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, appendix A–4.
		ii. Measure O_2 at the inlet and outlet of the control device;	(1) Method 3, 3A, or 3B of 40 CFR part 60, appendix A–2	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for NO_X concentration.

Each	Complying with the requirement to	You must	Using	According to the following requirements
		iii. If necessary, measure moisture content at the inlet and outlet of the control device; and	(2) Method 4 of 40 CFR part 60, appendix A–3, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03 (incorporated by reference, see § 60.17)	(c) Measurements to determine moisture content must be made at the same time as the measurements for NO_X concentration.
		iv. Measure NO_X at the inlet and outlet of the control device.	(3) Method 7E of 40 CFR part 60, appendix A–4, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03 (incorporated by reference, see § 60.17)	(d) NO_X concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
	b. Limit the concentration of NO_X in the stationary CI internal combustion engine exhaust.	i. Select the sampling port location and number/ location of traverse points at the exhaust of the stationary internal combustion engine;		(a) For NO_X, O_2, and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line ('3-point long line'). If the duct is >12 inches in diameter *and* the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, appendix A–1, the duct may be sampled at '3-point long line'; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, appendix A–4.
		ii. Determine the O_2	(1) Method 3, 3A, or 3B of	(b) Measurements to determine O_2 concentration must be made at the same

Each	Complying with the requirement to	You must	Using	According to the following requirements
		concentration of the stationary internal combustion engine exhaust at the sampling port location;	40 CFR part 60, appendix A–2	time as the measurement for NO_X concentration.
		iii. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and	(2) Method 4 of 40 CFR part 60, appendix A–3, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03 (incorporated by reference, see § 60.17)	(c) Measurements to determine moisture content must be made at the same time as the measurement for NO_X concentration.
		iv. Measure NO_X at the exhaust of the stationary internal combustion engine; if using a control device, the sampling site must be located at the outlet of the control device.	(3) Method 7E of 40 CFR part 60, appendix A–4, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03 (incorporated by reference, see § 60.17)	(d) NO_X concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
	c. Reduce PM emissions by 60 percent or more	i. Select the sampling port location and the number of traverse	(1) Method 1 or 1A of 40 CFR part 60, appendix A–1	(a) Sampling sites must be located at the inlet and outlet of the control device.

Each	Complying with the requirement to	You must	Using	According to the following requirements
		points;		
		ii. Measure O_2 at the inlet and outlet of the control device;	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A–2	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for PM concentration.
		iii. If necessary, measure moisture content at the inlet and outlet of the control device; and	(3) Method 4 of 40 CFR part 60, appendix A–3	(c) Measurements to determine and moisture content must be made at the same time as the measurements for PM concentration.
		iv. Measure PM at the inlet and outlet of the control device.	(4) Method 5 of 40 CFR part 60, appendix A–3	(d) PM concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
	d. Limit the concentration of PM in the stationary CI internal combustion engine exhaust	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A–1	(a) If using a control device, the sampling site must be located at the outlet of the control device.
		ii. Determine the O_2 concentration of the stationary internal combustion engine exhaust at the sampling port location;	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A–2	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for PM concentration.
		iii. If necessary, measure moisture	(3) Method 4 of 40 CFR part 60, appendix	(c) Measurements to determine moisture content must be made at the same time as the measurements for PM concentration.

Each	Complying with the requirement to	You must	Using	According to the following requirements
		content of the stationary internal combustion engine exhaust at the sampling port location; and	A–3	
		iv. Measure PM at the exhaust of the stationary internal combustion engine.	(4) Method 5 of 40 CFR part 60, appendix A–3	(d) PM concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.

[79 FR 11251, Feb. 27, 2014]

Table 8 to Subpart IIII of Part 60—Applicability of General Provisions to Subpart IIII

[As stated in § 60.4218, you must comply with the following applicable General Provisions:]

General Provisions citation	Subject of citation	Applies to subpart	Explanation
§ 60.1	General applicability of the General Provisions	Yes	
§ 60.2	Definitions	Yes	Additional terms defined in § 60.4219.
§ 60.3	Units and abbreviations	Yes	
§ 60.4	Address	Yes	
§ 60.5	Determination of construction or modification	Yes	
§ 60.6	Review of plans	Yes	
§ 60.7	Notification and Recordkeeping	Yes	Except that § 60.7 only applies as specified in § 60.4214(a).
§ 60.8	Performance tests	Yes	Except that § 60.8 only applies to stationary CI ICE with a displacement of (≥30 liters per cylinder and engines that are not certified.
§ 60.9	Availability of information	Yes	

General Provisions citation	Subject of citation	Applies to subpart	Explanation
§ 60.10	State Authority	Yes	
§ 60.11	Compliance with standards and maintenance requirements	No	Requirements are specified in subpart IIII.
§ 60.12	Circumvention	Yes	
§ 60.13	Monitoring requirements	Yes	Except that § 60.13 only applies to stationary CI ICE with a displacement of (≥30 liters per cylinder.
§ 60.14	Modification	Yes	
§ 60.15	Reconstruction	Yes	
§ 60.16	Priority list	Yes	
§ 60.17	Incorporations by reference	Yes	
§ 60.18	General control device requirements	No	
§ 60.19	General notification and reporting requirements	Yes	

Appendix F

40 C.F.R. § 61 Subpart FF—*National Emission Standard for Benzene Waste Operations*

Title 40 —Protection of Environment
Chapter I —Environmental Protection Agency
Subchapter C —Air Programs
Part 61 —National Emission Standards for Hazardous Air Pollutants

Authority: 42 U.S.C. 7401 *et seq.*

Source: 38 FR 8826, Apr. 6, 1973, unless otherwise noted.

Subpart FF—National Emission Standard for Benzene Waste Operations

Source: 55 FR 8346, Mar. 7, 1990, unless otherwise noted.

§ 61.340 Applicability.

(a) The provisions of this subpart apply to owners and operators of chemical manufacturing plants, coke by-product recovery plants, and petroleum refineries.

(b) The provisions of this subpart apply to owners and operators of hazardous waste treatment, storage, and disposal facilities that treat, store, or dispose of hazardous waste generated by any facility listed in paragraph (a) of this section. The waste streams at hazardous waste treatment, storage, and disposal facilities subject to the provisions of this subpart are the benzene-containing hazardous waste from any facility listed in paragraph (a) of this section. A hazardous waste treatment, storage, and disposal facility is a facility that must obtain a hazardous waste management permit under subtitle C of the Solid Waste Disposal Act.

(c) At each facility identified in paragraph (a) or (b) of this section, the following waste is exempt from the requirements of this subpart:

(1) Waste in the form of gases or vapors that is emitted from process fluids:

(2) Waste that is contained in a segregated stormwater sewer system.

(d) At each facility identified in paragraph (a) or (b) of this section, any gaseous stream from a waste management unit, treatment process, or wastewater treatment system routed to a fuel gas system, as defined in § 61.341, is exempt from this subpart. No testing, monitoring, recordkeeping, or reporting is required under this subpart for any gaseous stream from a waste management unit, treatment process, or wastewater treatment unit routed to a fuel gas system.

[55 FR 8346, Mar. 7, 1990, as amended at 55 FR 37231, Sept. 10, 1990; 58 FR 3095, Jan. 7, 1993; 67 FR 68531, Nov. 12, 2002]

§ 61.341 Definitions.

Benzene concentration means the fraction by weight of benzene in a waste as determined in accordance with the procedures specified in § 61.355 of this subpart.

Car-seal means a seal that is placed on a device that is used to change the position of a valve (e.g., from opened to closed) in such a way that the position of the valve cannot be changed without breaking the seal.

Chemical manufacturing plant means any facility engaged in the production of chemicals by chemical, thermal, physical, or biological processes for use as a product, co-product, by-product, or intermediate including but not limited to industrial organic chemicals, organic pesticide products, pharmaceutical preparations, paint and allied products, fertilizers, and agricultural chemicals. Examples of chemical manufacturing plants include facilities at which process units are operated to produce one or more of the following chemicals: benzenesulfonic acid, benzene, chlorobenzene, cumene, cyclohexane, ethylene, ethylbenzene, hydroquinone, linear alklylbenzene, nitrobenzene, resorcinol, sulfolane, or styrene.

Closed-vent system means a system that is not open to the atmosphere and is composed of piping, ductwork, connections, and, if necessary, flow inducing devices that transport gas or vapor from an emission source to a control device.

Coke by-product recovery plant means any facility designed and operated for the separation and recovery of coal tar derivatives (by-products) evolved from coal during the coking process of a coke oven battery.

Container means any portable waste management unit in which a material is stored, transported, treated, or otherwise handled. Examples of containers are drums, barrels, tank trucks, barges, dumpsters, tank cars, dump trucks, and ships.

Control device means an enclosed combustion device, vapor recovery system, or flare.

Cover means a device or system which is placed on or over a waste placed in a waste management unit so that the entire waste surface area is enclosed and sealed to minimize air emissions. A cover may have openings necessary for operation, inspection, and maintenance of the waste management unit such as access hatches, sampling ports, and gauge wells provided that each opening is closed and sealed when not in use. Example of covers include a fixed roof installed on a tank, a lid installed on a container, and an air-supported enclosure installed over a waste management unit.

External floating roof means a pontoon-type or double-deck type cover with certain rim sealing mechanisms that rests on the liquid surface in a waste management unit with no fixed roof.

Facility means all process units and product tanks that generate waste within a stationary source, and all waste management units that are used for waste treatment, storage, or disposal within a stationary source.

Fixed roof means a cover that is mounted on a waste management unit in a stationary manner and that does not move with fluctuations in liquid level.

Floating roof means a cover with certain rim sealing mechanisms consisting of a double deck, pontoon single deck, internal floating cover or covered floating roof, which rests upon and is supported by the liquid being contained, and is equipped with a closure seal or seals to close the space between the roof edge and unit wall.

Flow indicator means a device which indicates whether gas flow is present in a line or vent system.

Fuel gas system means the offsite and onsite piping and control system that gathers gaseous streams generated by facility operations, may blend them with sources of gas, if available, and transports the blended gaseous fuel at suitable pressures for use as fuel in heaters, furnaces, boilers, incinerators, gas turbines, and other combustion devices located within or outside the facility. The fuel is piped directly to each individual combustion device, and the system typically operates at pressures over atmospheric.

Individual drain system means the system used to convey waste from a process unit, product storage tank, or waste management unit to a waste management unit. The term includes all process drains and common junction boxes, together with their associated sewer lines and other junction boxes, down to the receiving waste management unit.

Internal floating roof means a cover that rests or floats on the liquid surface inside a waste management unit that has a fixed roof.

Liquid-mounted seal means a foam or liquid-filled primary seal mounted in contact with the liquid between the waste management unit wall and the floating roof continuously around the circumference.

Loading means the introduction of waste into a waste management unit but not necessarily to complete capacity (also referred to as filling).

Maximum organic vapor pressure means the equilibrium partial pressure exerted by the waste at the temperature equal to the highest calendar-month average of the waste storage temperature for waste stored above or below the ambient temperature or at the local maximum monthly average temperature as reported by the National Weather Service for waste stored at the ambient temperature, as determined:

(1) In accordance with § 60.17(c); or

(2) As obtained from standard reference texts; or

(3) In accordance with § 60.17(a)(37); or

(4) Any other method approved by the Administrator.

No detectable emissions means less than 500 parts per million by volume (ppmv) above background levels, as measured by a detection instrument reading in accordance with the procedures specified in § 61.355(h) of this subpart.

Oil-water separator means a waste management unit, generally a tank or surface impoundment, used to separate oil from water. An oil-water separator consists of not only the separation unit but also the forebay and other separator basins, skimmers, weirs, grit chambers, sludge hoppers, and bar screens that are located directly after the individual drain system and prior to additional treatment units such as an air flotation unit, clarifier, or biological treatment unit. Examples of an oil-water separator incude an API separator, parallel-plate interceptor, and corrugated-plate interceptor with the associated ancillary equipment.

Petroleum refinery means any facility engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants, or other products through the distillation of petroleum, or through the redistillation, cracking, or reforming of unfinished petroleum derivatives.

Petroleum means the crude oil removed from the earth and the oils derived from tar sands, shale, and coal.

Point of waste generation means the location where the waste stream exits the process unit component or storage tank prior to handling or treatment in an operation that is not an integral part of the production process, or in the case of waste management units that generate new wastes after treatment, the location where the waste stream exits the waste management unit component.

Process unit means equipment assembled and connected by pipes or ducts to produce intermediate or final products. A process unit can be operated independently if supplied with sufficient fuel or raw materials and sufficient product storage facilities.

Process unit turnaround means the shutting down of the operations of a process unit, the purging of the contents of the process unit, the maintenance or repair work, followed by restarting of the process.

Process unit turnaround waste means a waste that is generated as a result of a process unit turnaround.

Process wastewater means water which comes in contact with benzene during manufacturing or processing operations conducted within a process unit. Process wastewater is not organic wastes, process fluids, product tank drawdown, cooling tower blowdown, steam trap condensate, or landfill leachate.

Process wastewater stream means a waste stream that contains only process wastewater.

Product tank means a stationary unit that is designed to contain an accumulation of materials that are fed to or produced by a process unit, and is constructed primarily of non-earthen materials (e.g., wood, concrete, steel, plastic) which provide structural support.

Product tank drawdown means any material or mixture of materials discharged from a product tank for the purpose of removing water or other contaminants from the product tank.

Safety device means a closure device such as a pressure relief valve, frangible disc, fusible plug, or any other type of device which functions exclusively to prevent physical damage or permanent deformation to a unit or its air emission control equipment by venting gases or vapors directly to the atmosphere during unsafe conditions resulting from an unplanned, accidental, or emergency event. For the purpose of this subpart, a safety device is not used for routine venting of gases or vapors from the vapor headspace underneath a cover such as during filling of the unit or to adjust the pressure in this vapor headspace in response to normal daily diurnal ambient temperature fluctuations. A safety device is designed to remain in a closed position during normal operations and open only when the internal pressure, or another relevant parameter, exceeds the device threshold setting applicable to the air emission control equipment as determined by the owner or operator based on manufacturer recommendations, applicable regulations, fire protection and prevention codes, standard engineering codes and practices, or other requirements for the safe handling of flammable, ignitable, explosive, reactive, or hazardous materials.

Segregated stormwater sewer system means a drain and collection system designed and operated for the sole purpose of collecting rainfall runoff at a facility, and which is segregated from all other individual drain systems.

Sewer line means a lateral, trunk line, branch line, or other enclosed conduit used to convey waste to a downstream waste management unit.

Slop oil means the floating oil and solids that accumulate on the surface of an oil-water separator.

Sour water stream means a stream that:

(1) Contains ammonia or sulfur compounds (usually hydrogen sulfide) at concentrations of 10 ppm by weight or more;

(2) Is generated from separation of water from a feed stock, intermediate, or product that contained ammonia or sulfur compounds; and

(3) Requires treatment to remove the ammonia or sulfur compounds.

Sour water stripper means a unit that:

(1) Is designed and operated to remove ammonia or sulfur compounds (usually hydrogen sulfide) from sour water streams;

(2) Has the sour water streams transferred to the stripper through hard piping or other enclosed system; and

(3) Is operated in such a manner that the offgases are sent to a sulfur recovery unit, processing unit, incinerator, flare, or other combustion device.

Surface impoundment means a waste management unit which is a natural topographic depression, man-made excavation, or diked area formed primarily of earthen materials (although it may be lined with man-made materials), which is designed to hold an accumulation of liquid wastes or waste containing free liquids, and which is not an injection well. Examples of surface impoundments are holding, storage, settling, and aeration pits, ponds, and lagoons.

Tank means a stationary waste management unit that is designed to contain an accumulation of waste and is constructed primarily of nonearthen materials (e.g., wood, concrete, steel, plastic) which provide structural support.

Treatment process means a stream stripping unit, thin-film evaporation unit, waste incinerator, or any other process used to comply with § 61.348 of this subpart.

Vapor-mounted seal means a foam-filled primary seal mounted continuously around the perimeter of a waste management unit so there is an annular vapor space underneath the seal. The annular vapor space is bounded by the bottom of the primary seal, the unit wall, the liquid surface, and the floating roof.

Waste means any material resulting from industrial, commercial, mining or agricultural operations, or from community activities that is discarded or is being accumulated, stored, or physically, chemically, thermally, or biologically treated prior to being discarded, recycled, or discharged.

Waste management unit means a piece of equipment, structure, or transport mechanism used in handling, storage, treatment, or disposal of waste. Examples of a waste management unit include a tank, surface impoundment, container, oil-water separator, individual drain system, steam stripping unit, thin-film evaporation unit, waste incinerator, and landfill.

Waste stream means the waste generated by a particular process unit, product tank, or waste management unit. The characteristics of the waste stream (e.g., flow rate, benzene concentration, water content) are determined at the point of waste generation. Examples of a waste stream include process wastewater, product tank drawdown, sludge and slop oil removed from waste management units, and landfill leachate.

Wastewater treatment system means any component, piece of equipment, or installation that receives, manages, or treats process wastewater, product tank drawdown, or landfill leachate prior to direct or indirect discharge in accordance with the National Pollutant Discharge Elimination System permit regulations under 40 CFR part 122. These systems typically include individual drain systems, oil-water separators, air flotation units, equalization tanks, and biological treatment units.

Water seal controls means a seal pot, p-leg trap, or other type of trap filled with water (e.g., flooded sewers that maintain water levels adequate to prevent air flow through the system) that creates a water barrier between the sewer line and the atmosphere. The water level of the seal must be maintained in the vertical leg of a drain in order to be considered a water seal.

[55 FR 8346, Mar. 7, 1990; 55 FR 12444, Apr. 3, 1990, as amended at 58 FR 3095, Jan. 7, 1993; 67 FR 68531, Nov. 12, 2002]

§ 61.342 Standards: General.

(a) An owner or operator of a facility at which the total annual benzene quantity from facility waste is less than 10 megagrams per year (Mg/yr) (11 ton/yr) shall be exempt from the requirements of paragraphs (b) and (c) of this section. The total annual benzene quantity from facility waste is the sum of the annual benzene quantity for each waste stream at the facility that has a flow-weighted annual average water content greater than 10 percent or that is mixed with water, or other wastes, at any time and the mixture has an annual average water content greater than 10 percent. The benzene quantity in a waste stream is to be counted only once without multiple counting if other waste streams are mixed with or generated from the original waste stream. Other specific requirements for calculating the total annual benzene waste quantity are as follows:

(1) Wastes that are exempted from control under §§ 61.342(c)(2) and 61.342(c)(3) are included in the calculation of the total annual benzene quantity if they have an annual average water content greater than 10 percent, or if they are mixed with water or other wastes at any time and the mixture has an annual average water content greater than 10 percent.

(2) The benzene in a material subject to this subpart that is sold is included in the calculation of the total annual benzene quantity if the material has an annual average water content greater than 10 percent.

(3) Benzene in wastes generated by remediation activities conducted at the facility, such as the excavation of contaminated soil, pumping and treatment of groundwater, and the recovery of product from soil or groundwater, are not included in the calculation of total annual benzene quantity for that facility. If the facility's total annual benzene quantity is 10 Mg/yr (11 ton/yr) or more, wastes generated by remediation activities are subject to the requirements of paragraphs (c) through (h) of this section. If the facility is managing remediation waste generated offsite, the benzene in this waste shall be included in the calculation of total annual benzene quantity in facility waste, if the

waste streams have an annual average water content greater than 10 percent, or if they are mixed with water or other wastes at any time and the mixture has an annual average water content greater than 10 percent.

(4) The total annual benzene quantity is determined based upon the quantity of benzene in the waste before any waste treatment occurs to remove the benzene except as specified in § 61.355(c)(1)(i)(A) through (C).

(b) Each owner or operator of a facility at which the total annual benzene quantity from facility waste is equal to or greater than 10 Mg/yr (11 ton/yr) as determined in paragraph (a) of this section shall be in compliance with the requirements of paragraphs (c) through (h) of this section no later than 90 days following the effective date, unless a waiver of compliance has been obtained under § 61.11, or by the initial startup for a new source with an initial startup after the effective date.

(1) The owner or operator of an existing source unable to comply with the rule within the required time may request a waiver of compliance under § 61.10.

(2) As part of the waiver application, the owner or operator shall submit to the Administrator a plan under § 61.10(b)(3) that is an enforceable commitment to obtain environmental benefits to mitigate the benzene emissions that result from extending the compliance date. The plan shall include the following information:

(i) A description of the method of compliance, including the control approach, schedule for installing controls, and quantity of the benzene emissions that result from extending the compliance date;

(ii) If the control approach involves a compliance strategy designed to obtain integrated compliance with multiple regulatory requirements, a description of the other regulations involved and their effective dates; and

(iii) A description of the actions to be taken at the facility to obtain mitigating environmental benefits, including how the benefits will be obtained, the schedule for these actions, and an estimate of the quantifiable benefits that directly result from these actions.

(c) Each owner or operator of a facility at which the total annual benzene quantity from facility waste is equal to or greater than 10 Mg/yr (11 ton/yr) as determined in paragraph (a) of this section shall manage and treat the facility waste as follows:

(1) For each waste stream that contains benzene, including (but not limited to) organic waste streams that contain less than 10 percent water and aqueous waste streams, even if the wastes are not discharged to an individual drain system, the owner or operator shall:

(i) Remove or destroy the benzene contained in the waste using a treatment process or wastewater treatment system that complies with the standards specified in § 61.348 of this subpart.

(ii) Comply with the standards specified in §§ 61.343 through 61.347 of this subpart for each waste management unit that receives or manages the waste stream prior to and during treatment of the waste stream in accordance with paragraph (c)(1)(i) of this section.

(iii) Each waste management unit used to manage or treat waste streams that will be recycled to a process shall comply with the standards specified in §§ 61.343 through 61.347. Once the waste stream is recycled to a process, including to a tank used for the storage of production process feed, product, or product intermediates, unless this tank is used primarily for the storage of wastes, the material is no longer subject to paragraph (c) of this section.

(2) A waste stream is exempt from paragraph (c)(1) of this section provided that the owner or operator demonstrates initially and, thereafter, at least once per year that the flow-weighted annual average benzene concentration for the waste stream is less than 10 ppmw as determined by the procedures specified in § 61.355(c)(2) or § 61.355(c)(3).

(3) A waste stream is exempt from paragraph (c)(1) of this section provided that the owner or operator demonstrates initially and, thereafter, at least once per year that the conditions specified in either paragraph (c)(3)(i) or (c)(3)(ii) of this section are met.

(i) The waste stream is process wastewater that has a flow rate less than 0.02 liters per minute (0.005 gallons per minute) or an annual wastewater quantity of less than 10 Mg/yr (11 ton/yr); or

(ii) All of the following conditions are met:

(A) The owner or operator does not choose to exempt process wastewater under paragraph (c)(3)(i) of this section,

(B) The total annual benzene quantity in all waste streams chosen for exemption in paragraph (c)(3)(ii) of this section does not exceed 2.0 Mg/yr (2.2 ton/yr) as determined in the procedures in § 61.355(j), and

(C) The total annual benzene quantity in a waste stream chosen for exemption, including process unit turnaround waste, is determined for the year in which the waste is generated.

(d) As an alternative to the requirements specified in paragraphs (c) and (e) of this section, an owner or operator of a facility at which the total annual benzene quantity from facility waste is equal to or greater than 10 Mg/yr (11 ton/yr) as determined in paragraph (a) of this section may elect to manage and treat the facility waste as follows:

(1) The owner or operator shall manage and treat facility waste other than process wastewater in accordance with the requirements of paragraph (c)(1) of this section.

(2) The owner or operator shall manage and treat process wastewater in accordance with the following requirements:

(i) Process wastewater shall be treated to achieve a total annual benzene quantity from facility process wastewater less than 1 Mg/yr (1.1 ton/yr). Total annual benzene from facility process wastewater shall be determined by adding together the annual benzene quantity at the point of waste generation for each untreated process wastewater stream plus the annual benzene quantity exiting the treatment process for each process wastewater stream treated in accordance with the requirements of paragraph (c)(1)(i) of this section.

(ii) Each treated process wastewater stream identified in paragraph (d)(2)(i) of this section shall be managed and treated in accordance with paragraph (c)(1) of this section.

(iii) Each untreated process wastewater stream identified in paragraph (d)(2)(i) of this section is exempt from the requirements of paragraph (c)(1) of this section.

(e) As an alternative to the requirements specified in paragraphs (c) and (d) of this section, an owner or operator of a facility at which the total annual benzene quantity from facility waste is equal to or greater than 10 Mg/yr (11 ton/yr) as determined in paragraph (a) of this section may elect to manage and treat the facility waste as follows:

(1) The owner or operator shall manage and treat facility waste with a flow-weighted annual average water content of less than 10 percent in accordance with the requirements of paragraph (c)(1) of this section; and

(2) The owner or operator shall manage and treat facility waste (including remediation and process unit turnaround waste) with a flow-weighted annual average water content of 10 percent or greater, on a volume basis as total water, and each waste stream that is mixed with water or wastes at any time such that the resulting mixture has an annual water content greater than 10 percent, in accordance with the following:

(i) The benzene quantity for the wastes described in paragraph (e)(2) of this section must be equal to or less than 6.0 Mg/yr (6.6 ton/yr), as determined in § 61.355(k). Wastes as described in paragraph (e)(2) of this section that are transferred offsite shall be included in the determination of benzene quantity as provided in § 61.355(k). The provisions of paragraph (f) of this section shall not apply to any owner or operator who elects to comply with the provisions of paragraph (e) of this section.

(ii) The determination of benzene quantity for each waste stream defined in paragraph (e)(2) of this section shall be made in accordance with § 61.355(k).

(f) Rather than treating the waste onsite, an owner or operator may elect to comply with paragraph (c)(1)(i) of this section by transferring the waste offsite to another facility where the waste is treated in accordance with the requirements of paragraph (c)(1)(i) of this section. The owner or operator transferring the waste shall:

(1) Comply with the standards specified in §§ 61.343 through 61.347 of this subpart for each waste management unit that receives or manages the waste prior to shipment of the waste offsite.

(2) Include with each offsite waste shipment a notice stating that the waste contains benzene which is required to be managed and treated in accordance with the provisions of this subpart.

(g) Compliance with this subpart will be determined by review of facility records and results from tests and inspections using methods and procedures specified in § 61.355 of this subpart.

(h) Permission to use an alternative means of compliance to meet the requirements of §§ 61.342 through 61.352 of this subpart may be granted by the Administrator as provided in § 61.353 of this subpart.

[55 FR 8346, Mar. 7, 1990, as amended at 58 FR 3095, Jan. 7, 1993; 65 FR 62159, 62160, Oct. 17, 2000]

§ 61.343 Standards: Tanks.

(a) Except as provided in paragraph (b) of this section and in § 61.351, the owner or operator must meet the standards in paragraph (a)(1) or (2) of this section for each tank in which the waste stream is placed in accordance with § 61.342 (c)(1)(ii). The standards in this section apply to the treatment and storage of the waste stream in a tank, including dewatering.

(1) The owner or operator shall install, operate, and maintain a fixed-roof and closed-vent system that routes all organic vapors vented from the tank to a control device.

(i) The fixed-roof shall meet the following requirements:

(A) The cover and all openings (e.g., access hatches, sampling ports, and gauge wells) shall be designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, as determined initially and thereafter at least once per year by the methods specified in § 61.355(h) of this subpart.

(B) Each opening shall be maintained in a closed, sealed position (e.g., covered by a lid that is gasketed and latched) at all times that waste is in the tank except when it is necessary to use the opening for waste sampling or removal, or for equipment inspection, maintenance, or repair.

(C) If the cover and closed-vent system operate such that the tank is maintained at a pressure less than atmospheric pressure, then paragraph (a)(1)(i)(B) of this section does not apply to any opening that meets all of thefollowing conditions:

(*1*) The purpose of the opening is to provide dilution air to reduce the explosion hazard;

(*2*) The opening is designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, as determined initially and thereafter at least once per year by the methods specified in § 61.355(h); and

(*3*) The pressure is monitored continuously to ensure that the pressure in the tank remains below atmospheric pressure.

(ii) The closed-vent system and control device shall be designed and operated in accordance with the requirements of § 61.349 of this subpart.

(2) The owner or operator must install, operate, and maintain an enclosure and closed-vent system that routes all organic vapors vented from the tank, located inside the enclosure, to a control device in accordance with the requirements specified in paragraph (e) of this section.

(b) For a tank that meets all the conditions specified in paragraph (b)(1) of this section, the owner or operator may elect to comply with paragraph (b)(2) of this section as an alternative to the requirements specified in paragraph (a)(1) of this section.

(1) The waste managed in the tank complying with paragraph (b)(2) of this section shall meet all of the following conditions:

(i) Each waste stream managed in the tank must have a flow-weighted annual average water content less than or equal to 10 percent water, on a volume basis as total water.

(ii) The waste managed in the tank either:

(A) Has a maximum organic vapor pressure less than 5.2 kilopascals (kPa) (0.75 pounds per square inch (psi));

(B) Has a maximum organic vapor pressure less than 27.6 kPa (4.0 psi) and is managed in a tank having design capacity less than 151 m^3 (40,000 gal); or

(C) Has a maximum organic vapor pressure less than 76.6 kPa (11.1 psi) and is managed in a tank having a design capacity less than 75 m^3 (20,000 gal).

(2) The owner or operator shall install, operate, and maintain a fixed roof as specified in paragraph (a)(1)(i).

(3) For each tank complying with paragraph (b) of this section, one or more devices which vent directly to the atmosphere may be used on the tank provided each device remains in a closed, sealed position during normal operations except when the device needs to open to prevent physical damage or permanent deformation of the tank or cover resulting from filling or emptying the tank, diurnal temperature changes, atmospheric pressure changes or malfunction of the unit in accordance with good engineering and safety practices for handling flammable, explosive, or other hazardous materials.

(c) Each fixed-roof, seal, access door, and all other openings shall be checked by visual inspection initially and quarterly thereafter to ensure that no cracks or gaps occur and that access doors and other openings are closed and gasketed properly.

(d) Except as provided in § 61.350 of this subpart, when a broken seal or gasket or other problem is identified, or when detectable emissions are measured, first efforts at repair shall be made as soon as practicable, but not later than 45 calendar days after identification.

(e) Each owner or operator who controls air pollutant emissions by using an enclosure vented through a closed-vent system to a control device must meet the requirements specified in paragraphs (e)(1) through (4) of this section.

(1) The tank must be located inside a total enclosure. The enclosure must be designed and operated in accordance with the criteria for a permanent total enclosure as specified in “Procedure T—Criteria for and Verification of a Permanent or Temporary Total Enclosure” in 40 CFR 52.741, appendix B. The enclosure may have permanent or temporary openings to allow worker access; passage of material into or out of the enclosure by conveyor, vehicles, or other mechanical means; entry of permanent mechanical or electrical equipment; or direct airflow into the enclosure. The owner or operator must perform the verification procedure for the enclosure as specified in section 5.0 of Procedure T initially when the enclosure is first installed and, thereafter, annually. A facility that has conducted an initial compliance demonstration and that performs annual compliance demonstrations in accordance with the requirements for Tank Level 2 control requirements 40 CFR 264.1084(i) or 40 CFR 265(i) is not required to make repeat demonstrations of initial and continuous compliance for the purposes of this subpart.

(2) The enclosure must be vented through a closed-vent system to a control device that is designed and operated in accordance with the standards for control devices specified in § 61.349.

(3) Safety devices, as defined in this subpart, may be installed and operated as necessary on any enclosure, closed-vent system, or control device used to comply with the requirements of paragraphs (e)(1) and (2) of this section.

(4) The closed-vent system must be designed and operated in accordance with the requirements of § 61.349.

[55 FR 8346, Mar. 7, 1990, as amended at 55 FR 18331, May 2, 1990; 58 FR 3096, Jan. 7, 1993; 67 FR 68532, Nov. 12, 2002; 68 FR 6082, Feb. 6, 2003; 68 FR 67935, Dec. 4, 2003]

§ 61.344 Standards: Surface impoundments.

(a) The owner or operator shall meet the following standards for each surface impoundment in which waste is placed in accordance with § 61.342(c)(1)(ii) of this subpart:

(1) The owner or operator shall install, operate, and maintain on each surface impoundment a cover (e.g., air-supported structure or rigid cover) and closed-vent system that routes all organic vapors vented from the surface impoundment to a control device.

(i) The cover shall meet the following requirements:

(A) The cover and all openings (e.g., access hatches, sampling ports, and gauge wells) shall be designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, initially and thereafter at least once per year by the methods specified in § 61.355(h) of this subpart.

(B) Each opening shall be maintained in a closed, sealed position (e.g., covered by a lid that is gasketed and latched) at all times that waste is in the surface impoundment except when it is necessary to use the opening for waste sampling or removal, or for equipment inspection, maintenance, or repair.

(C) If the cover and closed-vent system operate such that the enclosure of the surface impoundment is maintained at a pressure less than atmospheric pressure, then paragraph (a)(1)(i)(B) of this section does not apply to any opening that meets all of the following conditions:

(*1*) The purpose of the opening is to provide dilution air to reduce the explosion hazard;

(*2*) The opening is designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, as determined initially and thereafter at least once per year by the methods specified in § 61.355(h) of this subpart; and

(*3*) The pressure is monitored continuously to ensure that the pressure in the enclosure of the surface impoundment remains below atmospheric pressure.

(D) The cover shall be used at all times that waste is placed in the surface impoundment except during removal of treatment residuals in accordance with 40 CFR 268.4 or closure of the surface impoundment in accordance with 40 CFR 264.228. (Note: the treatment residuals generated by these activities may be subject to the requirements of this part.)

(ii) The closed-vent system and control device shall be designed and operated in accordance with § 61.349 of this subpart.

(b) Each cover seal, access hatch, and all other openings shall be checked by visual inspection initially and quarterly thereafter to ensure that no cracks or gaps occur and that access hatches and other openings are closed and gasketed properly.

(c) Except as provided in § 61.350 of this subpart, when a broken seal or gasket or other problem is identified, or when detectable emissions are measured, first efforts at repair shall be made as soon as practicable, but not later than 15 calendar days after identification.

[55 FR 8346, Mar. 7, 1990, as amended at 58 FR 3097, Jan. 7, 1993]

§ 61.345 Standards: Containers.

(a) The owner or operator shall meet the following standards for each container in which waste is placed in accordance with § 61.342(c)(1)(ii) of this subpart:

(1) The owner or operator shall install, operate, and maintain a cover on each container used to handle, transfer, or store waste in accordance with the following requirements:

(i) The cover and all openings (e.g., bungs, hatches, and sampling ports) shall be designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, initially and thereafter at least once per year by the methods specified in § 61.355(h) of this subpart.

(ii) Except as provided in paragraph (a)(4) of this section, each opening shall be maintained in a closed, sealed position (e.g., covered by a lid that is gasketed and latched) at all times that waste is in the container except when it is necessary to use the opening for waste loading, removal, inspection, or sampling.

(2) When a waste is transferred into a container by pumping, the owner or operator shall perform the transfer using a submerged fill pipe. The submerged fill pipe outlet shall extend to within two fill pipe diameters of the bottom of the container while the container is being loaded. During loading of the waste, the cover shall remain in place and all openings shall be maintained in a closed, sealed position except for those openings required for the submerged fill pipe, those openings required for venting of the container to prevent physical damage or permanent deformation of the container or cover, and any openings complying with paragraph (a)(4) of this section.

(3) Treatment of a waste in a container, including aeration, thermal or other treatment, must be performed by the owner or operator in a manner such that while the waste is being treated the container meets the standards specified in paragraphs (a)(3)(i) through (iii) of this section, except for covers and closed-vent systems that meet the requirements in paragraph (a)(4) of this section.

(i) The owner or operator must either:

(A) Vent the container inside a total enclosure which is exhausted through a closed-vent system to a control device in accordance with the requirements of paragraphs (a)(3)(ii)(A) and (B) of this section; or

(B) Vent the covered or closed container directly through a closed-vent system to a control device in accordance with the requirements of paragraphs (a)(3)(ii)(B) and (C) of this section.

(ii) The owner or operator must meet the following requirements, as applicable to the type of air emission control equipment selected by the owner or operator:

(A) The total enclosure must be designed and operated in accordance with the criteria for a permanent total enclosure as specified in section 5 of the "Procedure T—Criteria for and Verification of a Permanent or Temporary Total Enclosure" in 40 CFR 52.741, appendix B. The enclosure may have permanent or temporary openings to allow worker access; passage of containers through the enclosure by conveyor or other mechanical means; entry of permanent mechanical or electrical equipment; or direct airflow into the enclosure. The owner or operator must perform the verification procedure for the enclosure as specified in section 5.0 of "Procedure T—Criteria for and Verification of a Permanent or Temporary Total Enclosure" initially when the enclosure is first installed and, thereafter, annually. A facility that has conducted an initial compliance demonstration and that performs annual compliance demonstrations in accordance with the Container Level

3 control requirements in 40 CFR 264.1086(e)(2)(i) or 40 CFR 265.1086(e)(2)(i) is not required to make repeat demonstrations of initial and continuous compliance for the purposes of this subpart.

(B) The closed-vent system and control device must be designed and operated in accordance with the requirements of § 61.349.

(C) For a container cover, the cover and all openings (*e.g.,* doors, hatches) must be designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, initially and thereafter at least once per year by the methods specified in § 61.355(h).

(iii) Safety devices, as defined in this subpart, may be installed and operated as necessary on any container, enclosure, closed-vent system, or control device used to comply with the requirements of paragraph (a)(3)(i) of this section.

(4) If the cover and closed-vent system operate such that the container is maintained at a pressure less than atmospheric pressure, the owner or operator may operate the system with an opening that is not sealed and kept closed at all times if the following conditions are met:

(i) The purpose of the opening is to provide dilution air to reduce the explosion hazard;

(ii) The opening is designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, as determined initially and thereafter at least once per year by methods specified in § 61.355(h); and

(iii) The pressure is monitored continuously to ensure that the pressure in the container remains below atmospheric pressure.

(b) Each cover and all openings shall be visually inspected initially and quarterly thereafter to ensure that they are closed and gasketed properly.

(c) Except as provided in § 61.350 of this subpart, when a broken seal or gasket or other problem is identified, first efforts at repair shall be made as soon as practicable, but not later than 15 calendar days after identification.

[55 FR 8346, Mar. 7, 1990, as amended at 58 FR 3097, Jan. 7, 1993; 67 FR 68532, Nov. 12, 2002; 68 FR 67936, Dec. 4, 2003]

§ 61.346 Standards: Individual drain systems.

(a) Except as provided in paragraph (b) of this section, the owner or operator shall meet the following standards for each individual drain system in which waste is placed in accordance with § 61.342(c)(1)(ii) of this subpart:

(1) The owner or operator shall install, operate, and maintain on each drain system opening a cover and closed-vent system that routes all organic vapors vented from the drain system to a control device.

(i) The cover shall meet the following requirements:

(A) The cover and all openings (e.g., access hatches, sampling ports) shall be designed to operate with no detactable emissions as indicated by an instrument reading of less than 500 ppmv above background, initially and thereafter at least once per year by the methods specified in § 61.355(h) of this subpart.

(B) Each opening shall be maintained in a closed, sealed position (e.g., covered by a lid that is gasketed and latched) at all times that waste is in the drain system except when it is necessary to use the opening for waste sampling or removal, or for equipment inspection, maintenance, or repair.

(C) If the cover and closed-vent system operate such that the individual drain system is maintained at a pressure less than atmospheric pressure, then paragraph (a)(1)(i)(B) of this section does not apply to any opening that meets all of the following conditions:

(*1*) The purpose of the opening is to provide dilution air to reduce the explosion hazard;

(*2*) The opening is designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, as determined initially and thereafter at least once per year by the methods specified in § 61.355(h); and

(*3*) The pressure is monitored continuously to ensure that the pressure in the individual drain system remains below atmospheric pressure.

(ii) The closed-vent system and control device shall be designed and operated in accordance with § 61.349 of this subpart.

(2) Each cover seal, access hatch, and all other openings shall be checked by visual inspection initially and quarterly thereafter to ensure that no cracks or gaps occur and that access hatches and other openings are closed and gasketed properly.

(3) Except as provided in § 61.350 of this subpart, when a broken seal or gasket or other problem is identified, or when detectable emissions are measured, first efforts at repair shall be made as soon as practicable, but not later than 15 calendar days after identification.

(b) As an alternative to complying with paragraph (a) of this section, an owner or operator may elect to comply with the following requirements:

(1) Each drain shall be equipped with water seal controls or a tightly sealed cap or plug.

(2) Each junction box shall be equipped with a cover and may have a vent pipe. The vent pipe shall be at least 90 cm (3 ft) in length and shall not exceed 10.2 cm (4 in) in diameter.

(i) Junction box covers shall have a tight seal around the edge and shall be kept in place at all times, except during inspection and maintenance.

(ii) One of the following methods shall be used to control emissions from the junction box vent pipe to the atmosphere:

(A) Equip the junction box with a system to prevent the flow of organic vapors from the junction box vent pipe to the atmosphere during normal operation. An example of such a system includes use of water seal controls on the junction box. A flow indicator shall be installed, operated, and maintained on each junction box vent pipe to ensure that organic vapors are not vented from the junction box to the atmosphere during normal operation.

(B) Connect the junction box vent pipe to a closed-vent system and control device in accordance with § 61.349 of this subpart.

(3) Each sewer line shall not be open to the atmosphere and shall be covered or enclosed in a manner so as to have no visual gaps or cracks in joints, seals, or other emission interfaces.

(4) Equipment installed in accordance with paragraphs (b)(1), (b)(2), or (b)(3) of this section shall be inspected as follows:

(i) Each drain using water seal controls shall be checked by visual or physical inspection initially and thereafter quarterly for indications of low water levels or other conditions that would reduce the effectiveness of water seal controls.

(ii) Each drain using a tightly sealed cap or plug shall be visually inspected initially and thereafter quarterly to ensure caps or plugs are in place and properly installed.

(iii) Each junction box shall be visually inspected initially and thereafter quarterly to ensure that the cover is in place and to ensure that the cover has a tight seal around the edge.

(iv) The unburied portion of each sewer line shall be visually inspected initially and thereafter quarterly for indication of cracks, gaps, or other problems that could result in benzene emissions.

(5) Except as provided in § 61.350 of this subpart, when a broken seal, gap, crack or other problem is identified, first efforts at repair shall be made as soon as practicable, but not later than 15 calendar days after identification.

[55 FR 8346, Mar. 7, 1990, as amended at 55 FR 37231, Sept. 10, 1990; 58 FR 3097, Jan. 7, 1993]

§ 61.347 Standards: Oil-water separators.

(a) Except as provided in § 61.352 of this subpart, the owner or operator shall meet the following standards for each oil-water separator in which waste is placed in accordance with § 61.342(c)(1)(ii) of this subpart:

(1) The owner or operator shall install, operate, and maintain a fixed-roof and closed-vent system that routes all organic vapors vented from the oil-water separator to a control device.

(i) The fixed-roof shall meet the following requirements:

(A) The cover and all openings (e.g., access hatches, sampling ports, and gauge wells) shall be designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, as determined initially and thereafter at least once per year by the methods specified in § 61.355(h) of this subpart.

(B) Each opening shall be maintained in a closed, sealed position (e.g., covered by a lid that is gasketed and latched) at all times that waste is in the oil-water separator except when it is necessary to use the opening for waste sampling or removal, or for equipment inspection, maintenance, or repair.

(C) If the cover and closed-vent system operate such that the oil-water separator is maintained at a pressure less than atmospheric pressure, then paragraph (a)(1)(i)(B) of this section does not apply to any opening that meets all of the following conditions:

(*1*) The purpose of the opening is to provide dilution air to reduce the explosion hazard;

(*2*) The opening is designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, as determined initially and thereafter at least once per year by the methods specified in § 61.355(h); and

(3) The pressure is monitored continuously to ensure that the pressure in the oil-water separator remains below atmospheric pressure.

(ii) The closed-vent system and control device shall be designed and operated in accordance with the requirements of § 61.349 of this subpart.

(b) Each cover seal, access hatch, and all other openings shall be checked by visual inspection initially and quarterly thereafter to ensure that no cracks or gaps occur between the cover and oil-water separator wall and that access hatches and other openings are closed and gasketed properly.

(c) Except as provided in § 61.350 of this subpart, when a broken seal or gasket or other problem is identified, or when detectable emissions are measured, first efforts at repair shall be made as soon as practicable, but not later than 15 calendar days after identification.

[55 FR 8346, Mar. 7, 1990, as amended at 58 FR 3098, Jan. 7, 1993]

§ 61.348 Standards: Treatment processes.

(a) Except as provided in paragraph (a)(5) of this section, the owner or operator shall treat the waste stream in accordance with the following requirements:

(1) The owner or operator shall design, install, operate, and maintain a treatment process that either:

(i) Removes benzene from the waste stream to a level less than 10 parts per million by weight (ppmw) on a flow-weighted annual average basis,

(ii) Removes benzene from the waste stream by 99 percent or more on a mass basis, or

(iii) Destroys benzene in the waste stream by incinerating the waste in a combustion unit that achieves a destruction efficiency of 99 percent or greater for benzene.

(2) Each treatment process complying with paragraphs (a)(1)(i) or (a)(1)(ii) of this section shall be designed and operated in accordance with the appropriate waste management unit standards specified in §§ 61.343 through 61.347 of this subpart. For example, if a treatment process is a tank, then the owner or operator shall comply with § 61.343 of this subpart.

(3) For the purpose of complying with the requirements specified in paragraph (a)(1)(i) of this section, the intentional or unintentional reduction in the benzene concentration of a waste stream by dilution of the waste stream with other wastes or materials is not allowed.

(4) An owner or operator may aggregate or mix together individual waste streams to create a combined waste stream for the purpose of facilitating treatment of waste to comply with the requirements of paragraph (a)(1) of this section except as provided in paragraph (a)(5) of this section.

(5) If an owner or operator aggregates or mixes any combination of process wastewater, product tank drawdown, or landfill leachate subject to § 61.342(c)(1) of this subpart together with other waste streams to create a combined waste stream for the purpose of facilitating management or treatment of waste in a wastewater treatment system, then the wastewater treatment system shall be operated in accordance with paragraph (b) of this section. These provisions apply to above-ground wastewater treatment systems as well as those that are at or below ground level.

(b) Except for facilities complying with § 61.342(e), the owner or operator that aggregates or mixes individual waste streams as defined in paragraph (a)(5) of this section for management and treatment in a wastewater treatment system shall comply with the following requirements:

(1) The owner or operator shall design and operate each waste management unit that comprises the wastewater treatment system in accordance with the appropriate standards specified in §§ 61.343 through 61.347 of this subpart.

(2) The provisions of paragraph (b)(1) of this section do not apply to any waste management unit that the owner or operator demonstrates to meet the following conditions initially and, thereafter, at least once per year:

(i) The benzene content of each waste stream entering the waste management unit is less than 10 ppmw on a flow-weighted annual average basis as determined by the procedures specified in § 61.355(c) of this subpart; and

(ii) The total annual benzene quantity contained in all waste streams managed or treated in exempt waste management units comprising the facility wastewater treatment systems is less than 1 Mg/yr (1.1 ton/yr). For this determination, total annual benzene quantity shall be calculated as follows:

(A) The total annual benzene quantity shall be calculated as the sum of the individual benzene quantities determined at each location where a waste stream first enters an exempt waste management unit. The benzene quantity discharged from an exempt waste management unit shall not be included in this calculation.

(B) The annual benzene quantity in a waste stream managed or treated in an enhanced biodegradation unit shall not be included in the calculation of the total annual benzene quantity, if the enhanced biodegradation unit is the first exempt unit in which the waste is managed or treated. A unit shall be considered enhanced biodegradation if it is a suspended-growth process that generates biomass, uses recycled biomass, and periodically removes biomass from the process. An enhanced biodegradation unit typically operates at a food-to-microorganism ratio in the range of 0.05 to 1.0 kg of biological oxygen demand per kg of biomass per day, a mixed liquor suspended solids ratio in the range of 1 to 8 grams per liter (0.008 to 0.7 pounds per liter), and a residence time in the range of 3 to 36 hours.

(c) The owner and operator shall demonstrate that each treatment process or wastewater treatment system unit, except as provided in paragraph (d) of this section, achieves the appropriate conditions specified in paragraphs (a) or (b) of this section in accordance with the following requirements:

(1) Engineering calculations in accordance with requirements specified in § 61.356(e) of this subpart; or

(2) Performance tests conducted using the test methods and procedures that meet the requirements specified in § 61.355 of this subpart.

(d) A treatment process or waste stream is in compliance with the requirements of this subpart and exempt from the requirements of paragraph (c) of this section provided that the owner or operator documents that the treatment process or waste stream is in compliance with other regulatory requirements as follows:

(1) The treatment process is a hazardous waste incinerator for which the owner or operator has been issued a final permit under 40 CFR part 270 and complies with the requirements of 40 CFR part 264, subpart O;

(2) The treatment process is an industrial furnace or boiler burning hazardous waste for energy recovery for which the owner or operator has been issued a final permit under 40 CFR part 270 and complies with the requirements of 40 CFR part 266, subpart D;

(3) The waste stream is treated by a means or to a level that meets benzene-specific treatment standards in accordance with the Land Disposal Restrictions under 40 CFR part 268, and the treatment process is designed and operated with a closed-vent system and control device meeting the requirements of § 61.349 of this subpart;

(4) The waste stream is treated by a means or to a level that meets benzene-specific effluent limitations or performance standards in accordance with the Effluent Guidelines and Standards under 40 CFR parts 401–464, and the treatment process is designed and operated with a closed-vent system and control device meeting the requirements of § 61.349 of this subpart; or

(5) The waste stream is discharged to an underground injection well for which the owner or operator has been issued a final permit under 40 CFR part 270 and complies with the requirements of 40 CFR part 122.

(e) Except as specified in paragraph (e)(3) of this section, if the treatment process or wastewater treatment system unit has any openings (e.g., access doors, hatches, etc.), all such openings shall be sealed (e.g., gasketed, latched, etc.) and kept closed at all times when waste is being treated, except during inspection and maintenance.

(1) Each seal, access door, and all other openings shall be checked by visual inspections initially and quarterly thereafter to ensure that no cracks or gaps occur and that openings are closed and gasketed properly.

(2) Except as provided in § 61.350 of this subpart, when a broken seal or gasket or other problem is identified, first efforts at repair shall be made as soon as practicable, but not later than 15 calendar days after identification.

(3) If the cover and closed-vent system operate such that the treatment process and wastewater treatment system unit are maintained at a pressure less than atmospheric pressure, the owner or operator may operate the system with an opening that is not sealed and kept closed at all times if the following conditions are met:

(i) The purpose of the opening is to provide dilution air to reduce the explosion hazard;

(ii) The opening is designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, as determined initially and thereafter at least once per year by the methods specified in § 61.355(h); and

(iii) The pressure is monitored continuously to ensure that the pressure in the treatment process and wastewater treatment system unit remain below atmospheric pressure.

(f) Except for treatment processes complying with paragraph (d) of this section, the Administrator may request at any time an owner or operator demonstrate that a treatment process or wastewater treatment system unit meets the applicable requirements specified in paragraphs (a) or (b) of this section by conducting a performance test using the test methods and procedures as required in § 61.355 of this subpart.

(g) The owner or operator of a treatment process or wastewater treatment system unit that is used to comply with the provisions of this section shall monitor the unit in accordance with the applicable requirements in § 61.354 of this subpart.

[55 FR 8346, Mar. 7, 1990, as amended at 55 FR 37231, Sept. 10, 1990; 58 FR 3098, Jan. 7, 1993; 65 FR 62160, Oct. 17, 2000]

§ 61.349 Standards: Closed-vent systems and control devices.

(a) For each closed-vent system and control device used to comply with standards in accordance with §§ 61.343 through 61.348 of this subpart, the owner or operator shall properly design, install, operate, and maintain the closed-vent system and control device in accordance with the following requirements:

(1) The closed-vent system shall:

(i) Be designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, as determined initially and thereafter at least once per year by the methods specified in § 61.355(h) of this subpart.

(ii) Vent systems that contain any bypass line that could divert the vent stream away from a control device used to comply with the provisions of this subpart shall install, maintain, and operate according to the manufacturer's specifications a flow indicator that provides a record of vent stream flow away from the control device at least once every 15 minutes, except as provided in paragraph (a)(1)(ii)(B) of this section.

(A) The flow indicator shall be installed at the entrance to any bypass line that could divert the vent stream away from the control device to the atmosphere.

(B) Where the bypass line valve is secured in the closed position with a car-seal or a lock-and-key type configuration, a flow indicator is not required.

(iii) All gauging and sampling devices shall be gas-tight except when gauging or sampling is taking place.

(iv) For each closed-vent system complying with paragraph (a) of this section, one or more devices which vent directly to the atmosphere may be used on the closed-vent system provided each device remains in a closed, sealed position during normal operations except when the device needs to open to prevent physical damage or permanent deformation of the closed-vent system resulting from malfunction of the unit in accordance with good engineering and safety practices for handling flammable, explosive, or other hazardous materials.

(2) The control device shall be designed and operated in accordance with the following conditions:

(i) An enclosed combustion device (e.g., a vapor incinerator, boiler, or process heater) shall meet one of the following conditions:

(A) Reduce the organic emissions vented to it by 95 weight percent or greater;

(B) Achieve a total organic compound concentration of 20 ppmv (as the sum of the concentrations for individual compounds using Method 18) on a dry basis corrected to 3 percent oxygen; or

(C) Provide a minimum residence time of 0.5 seconds at a minimum temperature of 760 °C (1,400 °F). If a boiler or process heater issued as the control device, then the vent stream shall be introduced into the flame zone of the boiler or process heater.

(ii) A vapor recovery system (e.g., a carbon adsorption system or a condenser) shall recover or control the organic emissions vented to it with an efficiency of 95 weight percent or greater, or shall recover or control the benzene emissions vented to it with an efficiency of 98 weight percent or greater.

(iii) A flare shall comply with the requirements of 40 CFR 60.18.

(iv) A control device other than those described in paragraphs (a)(2) (i) through (iii) of this section may be used provided that the following conditions are met:

(A) The device shall recover or control the organic emissions vented to it with an efficiency of 95 weight percent or greater, or shall recover or control the benzene emissions vented to it with an efficiency of 98 weight percent or greater.

(B) The owner or operator shall develop test data and design information that documents the control device will achieve an emission control efficiency of either 95 percent or greater for organic compounds or 98 percent or greater for benzene.

(C) The owner or operator shall identify:

(*1*) The critical operating parameters that affect the emission control performance of the device;

(*2*) The range of values of these operating parameters that ensure the emission control efficiency specified in paragraph (a)(2)(iv)(A) of this section is maintained during operation of the device; and

(*3*) How these operating parameters will be monitored to ensure the proper operation and maintenance of the device.

(D) The owner or operator shall submit the information and data specified in paragraphs (a)(2)(iv) (B) and (C) of this section to the Administrator prior to operation of the alternative control device.

(E) The Administrator will determine, based on the information submitted under paragraph (a)(2)(iv)(D) of this section, if the control device subiect to paragraph (a)(2)(iv) of this section meets the requirements of § 61.349. The control device subject to paragraph (a)(2)(iv) of this section may be operated prior to receiving approval from the Administrator. However, if the Administrator determines that the control device does not meet the requirements of § 61.349, the facility may be subject to enforcement action beginning from the time the control device began operation.

(b) Each closed-vent system and control device used to comply with this subpart shall be operated at all times when waste is placed in the waste management unit vented to the control device except when maintenance or repair of the waste management unit cannot be completed without a shutdown of the control device.

(c) An owner and operator shall demonstrate that each control device, except for a flare, achieves the appropriate conditions specified in paragraph (a)(2) of this section by using one of the following methods:

(1) Engineering calculations in accordance with requirements specified in § 61.356(f) of this subpart; or

(2) Performance tests conducted using the test methods and procedures that meet the requirements specified in § 61.355 of this subpart.

(d) An owner or operator shall demonstrate compliance of each flare in accordance with paragraph (a)(2)(iii) of this section.

(e) The Administrator may request at any time an owner or operator demonstrate that a control device meets the applicable conditions specified in paragraph (a)(2) of this section by conducting a performance test using the test methods and procedures as required in § 61.355, and for control devices subject to paragraph (a)(2)(iv) of this section, the Administrator may specify alternative test methods and procedures, as appropriate.

(f) Each closed-vent system and control device shall be visually inspected initially and quarterly thereafter. The visual inspection shall include inspection of ductwork and piping and connections to covers and control devices for evidence of visable defects such as holes in ductwork or piping and loose connections.

(g) Except as provided in § 61.350 of this subpart, if visible defects are observed during an inspection, or if other problems are identified, or if detectable emissions are measured, a first effort to repair the closed-vent system and control device shall be made as soon as practicable but no later than 5 calendar days after detection. Repair shall be completed no later than 15 calendar days after the emissions are detected or the visible defect is observed.

(h) The owner or operator of a control device that is used to comply with the provisions of this section shall monitor the control device in accordance with § 61.354(c) of this subpart.

[55 FR 8346, Mar. 7, 1990; 55 FR 12444, Apr. 3, 1990, as amended at 55 FR 37231, Sept. 10, 1990; 58 FR 3098, Jan. 7, 1993; 65 FR 62160, Oct. 17, 2000]

§ 61.350 Standards: Delay of repair.

(a) Delay of repair of facilities or units that are subject to the provisions of this subpart will be allowed if the repair is technically impossible without a complete or partial facility or unit shutdown.

(b) Repair of such equipment shall occur before the end of the next facility or unit shutdown.

§ 61.351 Alternative standards for tanks.

(a) As an alternative to the standards for tanks specified in § 61.343 of this subpart, an owner or operator may elect to comply with one of the following:

(1) A fixed roof and internal floating roof meeting the requirements in 40 CFR 60.112b(a)(1);

(2) An external floating roof meeting the requirements of 40 CFR 60.112b (a)(2); or

(3) An alternative means of emission limitation as described in 40 CFR 60.114b.

(b) If an owner or operator elects to comply with the provisions of this section, then the owner or operator is exempt from the provisions of § 61.343 of this subpart applicable to the same facilities.

[55 FR 8346, Mar. 7, 1990, as amended at 55 FR 37231, Sept. 10, 1990]

§ 61.352 Alternative standards for oil-water separators.

(a) As an alternative to the standards for oil-water separators specified in § 61.347 of this subpart, an owner or operator may elect to comply with one of the following:

(1) A floating roof meeting the requirements in 40 CFR 60.693–2(a); or

(2) An alternative means of emission limitation as described in 40 CFR 60.694.

(b) For portions of the oil-water separator where it is infeasible to construct and operate a floating roof, such as over the weir mechanism, a fixed roof vented to a vapor control device that meets the requirements in §§ 61.347 and 61.349 of this subpart shall be installed and operated.

(c) Except as provided in paragraph (b) of this section, if an owner or operator elects to comply with the provisions of this section, then the owner or operator is exempt from the provisions in § 61.347 of this subpart applicable to the same facilities.

§ 61.353 Alternative means of emission limitation.

(a) If, in the Administrator's judgment, an alternative means of emission limitation will achieve a reduction in benzene emissions at least equivalent to the reduction in benzene emissions from the source achieved by the applicable design, equipment, work practice, or operational requirements in §§ 61.342 through 61.349, the Administrator will publish in the FEDERAL REGISTER a notice permitting the use of the alternative means for purposes of compliance with that requirement. The notice may condition the permission on requirements related to the operation and maintenance of the alternative means.

(b) Any notice under paragraph (a) of this section shall be published only after public notice and an opportunity for a hearing.

(c) Any person seeking permission under this section shall collect, verify, and submit to the Administrator information showing that the alternative means achieves equivalent emission reductions.

[55 FR 8346, Mar. 7, 1990, as amended at 58 FR 3099, Jan. 7, 1993]

§ 61.354 Monitoring of operations.

(a) Except for a treatment process or waste stream complying with § 61.348(d), the owner or operator shall monitor each treatment process or wastewater treatment system unit to ensure the unit is properly operated and maintained by one of the following monitoring procedures:

(1) Measure the benzene concentration of the waste stream exiting the treatment process complying with § 61.348(a)(1)(i) at least once per month by collecting and analyzing one or more samples using the procedures specified in § 61.355(c)(3).

(2) Install, calibrate, operate, and maintain according to manufacturer's specifications equipment to continuously monitor and record a process parameter (or parameters) for the treatment process or wastewater treatment system unit that indicates proper system operation. The owner or operator shall inspect at least once each operating day the data recorded by the monitoring equipment (e.g., temperature monitor or flow indicator) to ensure that the unit is operating properly.

(b) If an owner or operator complies with the requirements of § 61.348(b), then the owner or operator shall monitor each wastewater treatment system to ensure the unit is properly operated and maintained by the appropriate monitoring procedure as follows:

(1) For the first exempt waste management unit in each waste treatment train, other than an enhanced biodegradation unit, measure the flow rate, using the procedures of § 61.355(b), and the benzene concentration of each waste stream entering the unit at least once per month by collecting and analyzing one or more samples using the procedures specified in § 61.355(c)(3).

(2) For each enhanced biodegradation unit that is the first exempt waste management unit in a treatment train, measure the benzene concentration of each waste stream entering the unit at least once per month by collecting and analyzing one or more samples using the procedures specified in § 61.355(c)(3).

(c) An owner or operator subject to the requirements in § 61.349 of this subpart shall install, calibrate, maintain, and operate according to the manufacturer's specifications a device to continuously monitor the control device operation as specified in the following paragraphs, unless alternative monitoring procedures or requirements are approved for that facility by the Administrator. The owner or operator shall inspect at least once each operating day the data recorded by the monitoring equipment (e.g., temperature monitor or flow indicator) to ensure that the control device is operating properly.

(1) For a thermal vapor incinerator, a temperature monitoring device equipped with a continuous recorder. The device shall have an accuracy of ±1 percent of the temperature being monitored in °C or ±0.5 °C, whichever is greater. The temperature sensor shall be installed at a representative location in the combustion chamber.

(2) For a catalytic vapor incinerator, a temperature monitoring device equipped with a continuous recorder. The device shall be capable of monitoring temperature at two locations, and have an accuracy of ±1 percent of the temperature being monitored in °C or ±0.5 °C, whichever is greater. One temperature sensor shall be installed in the vent stream at the nearest feasible point to the catalyst bed inlet and a second temperature sensor shall be installed in the vent stream at the nearest feasible point to the catalyst bed outlet.

(3) For a flare, a monitoring device in accordance with 40 CFR 60.18(f)(2) equipped with a continuous recorder.

(4) For a boiler or process heater having a design heat input capacity less than 44 MW (150×10^6 BTU/hr), a temperature monitoring device equipped with a continuous recorder. The device shall have an accuracy of ±1 percent of the temperature being monitored in °C or ±0.5 °C, whichever is greater. The temperature sensor shall be installed at a representative location in the combustion chamber.

(5) For a boiler or process heater having a design heat input capacity greater than or equal to 44 MW (150×10^6 BTU/hr), a monitoring device equipped with a continuous recorder to measure a parameter(s) that indicates good combustion operating practices are being used.

(6) For a condenser, either:

(i) A monitoring device equipped with a continuous recorder to measure either the concentration level of the organic compounds or the concentration level of benzene in the exhaust vent stream from the condenser; or

(ii) A temperature monitoring device equipped with a continuous recorder. The device shall be capable of monitoring temperature at two locations, and have an accuracy of ±1 percent of the temperature being monitored in °C or ±0.5 °C, whichever is greater. One temperature sensor shall be installed at a location in the exhaust stream from the condenser, and a second temperature sensor shall be installed at a location in the coolant fluid exiting the condenser.

(7) For a carbon adsorption system that regenerates the carbon bed directly in the control device such as a fixed-bed carbon adsorber, either:

(i) A monitoring device equipped with a continuous recorder to measure either the concentration level of the organic compounds or the benzene concentration level in the exhaust vent stream from the carbon bed; or

(ii) A monitoring device equipped with a continuous recorder to measure a parameter that indicates the carbon bed is regenerated on a regular, predetermined time cycle.

(8) For a vapor recovery system other than a condenser or carbon adsorption system, a monitoring device equipped with a continuous recorder to measure either the concentration level of the organic compounds or the benzene concentration level in the exhaust vent stream from the control device.

(9) For a control device subject to the requirements of § 61.349(a)(2)(iv), devices to monitor the parameters as specified in § 61.349(a)(2)(iv)(C).

(d) For a carbon adsorption system that does not regenerate the carbon bed directly on site in the control device (e.g., a carbon canister), either the concentration level of the organic compounds or the concentration level of benzene in the exhaust vent stream from the carbon adsorption system shall be monitored on a regular schedule, and the existing carbon shall be replaced with fresh carbon immediately when carbon breakthrough is indicated. The device shall be monitored on a daily basis or at intervals no greater than 20 percent of the design carbon replacement interval, whichever is greater. As an alternative to conducting this monitoring, an owner or operator may replace the carbon in the carbon adsorption system with fresh carbon at a regular predetermined time interval that is less than the carbon replacement interval that is determined by the maximum design flow rate and either the organic concentration or the benzene concentration in the gas stream vented to the carbon adsorption system.

(e) An alternative operation or process parameter may be monitored if it can be demonstrated that another parameter will ensure that the control device is operated in conformance with these standards and the control device's design specifications.

(f) Owners or operators using a closed-vent system that contains any bypass line that could divert a vent stream from a control device used to comply with the provisions of this subpart shall do the following:

(1) Visually inspect the bypass line valve at least once every month, checking the position of the valve and the condition of the car-seal or closure mechanism required under § 61.349(a)(1)(ii) to ensure that the valve is maintained in the closed position and the vent stream is not diverted through the bypass line.

(2) Visually inspect the readings from each flow monitoring device required by § 61.349(a)(1)(ii) at least once each operating day to check that vapors are being routed to the control device as required.

(g) Each owner or operator who uses a system for emission control that is maintained at a pressure less than atmospheric pressure with openings to provide dilution air shall install, calibrate, maintain, and operate according to the manufacturer's specifications a device equipped with a continuous recorder to monitor the pressure in the unit to ensure that it is less than atmospheric pressure.

[55 FR 8346, Mar. 7, 1990, as amended at 58 FR 3099, Jan. 7, 1993; 65 FR 62160, Oct. 17, 2000]

§ 61.355 Test methods, procedures, and compliance provisions.

(a) An owner or operator shall determine the total annual benzene quantity from facility waste by the following procedure:

(1) For each waste stream subject to this subpart having a flow-weighted annual average water content greater than 10 percent water, on a volume basis as total water, or is mixed with water or other wastes at any time and the resulting mixture has an annual average water content greater than 10 percent as specified in § 61.342(a), the owner or operator shall:

(i) Determine the annual waste quantity for each waste stream using the procedures specified in paragraph (b) of this section.

(ii) Determine the flow-weighted annual average benzene concentration for each waste stream using the procedures specified in paragraph (c) of this section.

(iii) Calculate the annual benzene quantity for each waste stream by multiplying the annual waste quantity of the waste stream times the flow-weighted annual average benzene concentration.

(2) Total annual benzene quantity from facility waste is calculated by adding together the annual benzene quantity for each waste stream generated during the year and the annual benzene quantity for each process unit turnaround waste annualized according to paragraph (b)(4) of this section.

(3) If the total annual benzene quantity from facility waste is equal to or greater than 10 Mg/yr (11 ton/yr), then the owner or operator shall comply with the requirements of § 61.342 (c), (d), or (e).

(4) If the total annual benzene quantity from facility waste is less than 10 Mg/yr (11 ton/yr) but is equal to or greater than 1 Mg/yr (1.1 ton/yr), then the owner or operator shall:

(i) Comply with the recordkeeping requirements of § 61.356 and reporting requirements of § 61.357 of this subpart; and

(ii) Repeat the determination of total annual benzene quantity from facility waste at least once per year and whenever there is a change in the process generating the waste that could cause the total annual benzene quantity from facility waste to increase to 10 Mg/yr (11 ton/yr) or more.

(5) If the total annual benzene quantity from facility waste is less than 1 Mg/yr (1.1 ton/yr), then the owner or operator shall:

(i) Comply with the recordkeeping requirements of § 61.356 and reporting requirements of § 61.357 of this subpart; and

(ii) Repeat the determination of total annual benzene quantity from facility waste whenever there is a change in the process generating the waste that could cause the total annual benzene quantity from facility waste to increase to 1 Mg/yr (1.1 ton/yr) or more.

(6) The benzene quantity in a waste stream that is generated less than one time per year, except as provided for process unit turnaround waste in paragraph (b)(4) of this section, shall be included in the determination of total annual benzene quantity from facility waste for the year in which the waste is generated unless the waste stream is otherwise excluded from the determination of total annual benzene quantity from facility waste in accordance with paragraphs (a) through (c) of this section. The benzene quantity in this waste stream shall not be annualized or averaged over the time interval between the activities that resulted in generation of the waste, for purposes of determining the total annual benzene quantity from facility waste.

(b) For purposes of the calculation required by paragraph (a) of this section, an owner or operator shall determine the annual waste quantity at the point of waste generation, unless otherwise provided in paragraphs (b) (1), (2), (3), and (4) of this section, by one of the methods given in paragraphs (b) (5) through (7) of this section.

(1) The determination of annual waste quantity for sour water streams that are processed in sour water strippers shall be made at the point that the water exits the sour water stripper.

(2) The determination of annual waste quantity for wastes at coke by-product plants subject to and complying with the control requirements of § 61.132, 61.133, 61.134, or 61.139 of subpart L of this part shall be made at the location that the waste stream exits the process unit component or waste management unit controlled by that subpart or at the exit of the ammonia still, provided that the following conditions are met:

(i) The transfer of wastes between units complying with the control requirements of subpart L of this part, process units, and the ammonia still is made through hard piping or other enclosed system.

(ii) The ammonia still meets the definition of a sour water stripper in § 61.341.

(3) The determination of annual waste quantity for wastes that are received at hazardous waste treatment, storage, or disposal facilities from offsite shall be made at the point where the waste enters the hazardous waste treatment, storage, or disposal facility.

(4) The determination of annual waste quantity for each process unit turnaround waste generated only at 2 year or greater intervals, may be made by dividing the total quantity of waste generated during the most recent process unit turnaround by the time period (in the nearest tenth of a year) between the turnaround resulting in generation of the waste and the most recent preceding process turnaround for the unit. The resulting annual waste quantity shall be included in the calculation of the annual benzene quantity as provided in paragraph (a)(1)(iii) of this section for the year in which the turnaround occurs and for each subsequent year until the unit undergoes the next process turnaround. For estimates of total annual benzene quantity as specified in the 90-day report, required under § 61.357(a)(1), the owner or operator shall estimate the waste quantity generated during the most recent turnaround, and the time period between turnarounds in accordance with good engineering practices. If the owner or operator chooses not to annualize process unit turnaround waste, as specified in this paragraph, then the process unit turnaround waste quantity shall be included in the calculation of the annual benzene quantity for the year in which the turnaround occurs.

(5) Select the highest annual quantity of waste managed from historical records representing the most recent 5 years of operation or, if the facility has been in service for less than 5 years but at least 1 year, from historical records representing the total operating life of the facility;

(6) Use the maximum design capacity of the waste management unit; or

(7) Use measurements that are representative of maximum waste generation rates.

(c) For the purposes of the calculation required by §§ 61.355(a) of this subpart, an owner or operator shall determine the flow-weighted annual average ben- zene concentration in a manner that meets the requirements given in paragraph (c)(1) of this section using either of the methods given in paragraphs (c)(2) and (c)(3) of this section.

(1) The determination of flow-weighted annual average benzene concentration shall meet all of the following criteria:

(i) The determination shall be made at the point of waste generation except for the specific cases given in paragraphs (c)(1)(i)(A) through (D) of this section.

(A) The determination for sour water streams that are processed in sour water strippers shall be made at the point that the water exits the sour water stripper.

(B) The determination for wastes at coke by-product plants subject to and complying with the control requirements of § 61.132, 61.133, 61.134, or 61.139 of subpart L of this part shall be made at the location that the waste stream exits the process unit component or waste management unit controlled by that subpart or at the exit of the ammonia still, provided that the following conditions are met:

(*1*) The transfer of wastes between units complying with the control requirements of subpart L of this part, process units, and the ammonia still is made through hard piping or other enclosed system.

(*2*) The ammonia still meets the definition of a sour water stripper in § 61.341.

(C) The determination for wastes that are received from offsite shall be made at the point where the waste enters the hazardous waste treatment, storage, or disposal facility.

(D) The determination of flow-weighted annual average benzene concentration for process unit turnaround waste shall be made using either of the methods given in paragraph (c)(2) or (c)(3) of this section. The resulting flow-weighted annual average benzene concentration shall be included in the calculation of annual benzene quantity as provided in paragraph (a)(1)(iii) of this section for the year in which the turnaround occurs and for each subsequent year until the unit undergoes the next process unit turnaround.

(ii) Volatilization of the benzene by exposure to air shall not be used in the determination to reduce the benzene concentration.

(iii) Mixing or diluting the waste stream with other wastes or other materials shall not be used in the determination—to reduce the benzene concentration.

(iv) The determination shall be made prior to any treatment of the waste that removes benzene, except as specified in paragraphs (c)(1)(i)(A) through (D) of this section.

(v) For wastes with multiple phases, the determination shall provide the weighted-average benzene concentration based on the benzene concentration in each phase of the waste and the relative proportion of the phases.

(2) ***Knowledge of the waste.*** The owner or operator shall provide sufficient information to document the flow-weighted annual average benzene concentration of each waste stream. Examples of information that could constitute knowledge include material balances, records of chemicals purchases, or previous test results provided the results are still relevant to the current waste stream conditions. If test data are used, then the owner or operator shall provide documentation describing the testing protocol and the means by which sampling variability and analytical variability were accounted for in the determination of the flow-weighted annual average benzene concentration for the waste stream. When an owner or operator and the Administrator do not agree on determinations of the flow-weighted annual average benzene concentration based on knowledge of the waste, the procedures under paragraph (c)(3) of this section shall be used to resolve the disagreement.

(3) Measurements of the benzene concentration in the waste stream in accordance with the following procedures:

(i) Collect a minimum of three representative samples from each waste stream. Where feasible, samples shall be taken from an enclosed pipe prior to the waste being exposed to the atmosphere.

(ii) For waste in enclosed pipes, the following procedures shall be used:

(A) Samples shall be collected prior to the waste being exposed to the atmosphere in order to minimize the loss of benzene prior to sampling.

(B) A static mixer shall be installed in the process line or in a by-pass line unless the owner or operator demonstrates that installation of a static mixer in the line is not necessary to accurately determine the benzene concentration of the waste stream.

(C) The sampling tap shall be located within two pipe diameters of the static mixer outlet.

(D) Prior to the initiation of sampling, sample lines and cooling coil shall be purged with at least four volumes of waste.

(E) After purging, the sample flow shall be directed to a sample container and the tip of the sampling tube shall be kept below the surface of the waste during sampling to minimize contact with the atmosphere.

(F) Samples shall be collected at a flow rate such that the cooling coil is able to maintain a waste temperature less than 10 °C (50 °F).

(G) After filling, the sample container shall be capped immediately (within 5 seconds) to leave a minimum headspace in the container.

(H) The sample containers shall immediately be cooled and maintained at a temperature below 10 °C (50 °F) for transfer to the laboratory.

(iii) When sampling from an enclosed pipe is not feasible, a minimum of three representative samples shall be collected in a manner to minimize exposure of the sample to the atmosphere and loss of benzene prior to sampling.

(iv) Each waste sample shall be analyzed using one of the following test methods for determining the benzene concentration in a waste stream:

(A) Method 8020, Aromatic Volatile Organics, in "Test Methods for Evaluating Solid Waste, Physical/Chemical Methods," EPA Publication No. SW–846 (incorporation by reference as specified in § 61.18 of this part);

(B) Method 8021, Volatile Organic Compounds in Water by Purge and Trap Capillary Column Gas Chromatography with Photoionization and Electrolytic Conductivity Detectors in Series in "Test Methods for Evaluating Solid Waste, Physical/Chemical Methods," EPA Publication No. SW–846 (incorporation by reference as specified in § 61.18 of this part);

(C) Method 8240, Gas Chromatography/Mass Spectrometry for Volatile Organics in "Test Methods for Evaluating Solid Waste, Physical/Chemical Methods," EPA Publication No. SW–846 (incorporation by reference as specified in § 61.18 of this part);

(D) Method 8260, Gas Chromatography/Mass Spectrometry for Volatile Organics: Capillary Column Technique in "Test Methods for Evaluating Solid Waste, Physical/Chemical Methods," EPA Publication No. SW–846 (incorporation by reference as specified in § 61.18 of this part);

(E) Method 602, Purgeable Aromatics, as described in 40 CFR part 136, appendix A, Test Procedures for Analysis of Organic Pollutants, for wastewaters for which this is an approved EPA methods; or

(F) Method 624, Purgeables, as described in 40 CFR part 136, appendix A, Test Procedures for Analysis of Organic Pollutants, for wastewaters for which this is an approved EPA method.

(v) The flow-weighted annual average benzene concentration shall be calculated by averaging the results of the sample analyses as follows:

$$\bar{C} = \frac{1}{Q_t} \times \sum_{i=1}^{n} (Q_i)(C_i)$$

Where:

$\bar{C}$ = Flow-weighted annual average benzene concentration for waste stream, ppmw.

Q_t = Total annual waste quantity for waste stream, kg/yr (lb/yr).

n = Number of waste samples (at least 3).

Q_i = Annual waste quantity for waste stream represented by C_i, kg/yr (lb/yr).

C_i = Measured concentration of benzene in waste sample i, ppmw.

(d) An owner or operator using performance tests to demonstrate compliance of a treatment process with § 61.348 (a)(1)(i) shall measure the flow-weighted annual average benzene concentration of the waste stream exiting the treatment process by collecting and analyzing a minimum of three representative samples of the waste stream using the procedures in paragraph (c)(3) of this section. The test shall be conducted under conditions that exist when the treatment process is operating at the highest inlet waste stream flow rate and benzene content expected to occur. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a test. The owner or operator shall record all process information as is necessary to document the operating conditions during the test.

(e) An owner or operator using performance tests to demonstrate compliance of a treatment process with § 61.348(a)(1)(ii) of this subpart shall determine the percent reduction of benzene in the waste stream on a mass basis by the following procedure:

(1) The test shall be conducted under conditions that exist when the treatment process is operating at the highest inlet waste stream flow rate and benzene content expected to occur. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a test. The owner or operator shall record all process information as is necessary to document the operating conditions during the test.

(2) All testing equipment shall be prepared and installed as specified in the appropriate test methods.

(3) The mass flow rate of benzene entering the treatment process (E_b) shall be determined by computing the product of the flow rate of the waste stream entering the treatment process, as determined by the inlet flow meter, and the benzene concentration of the waste stream, as

determined using the sampling and analytical procedures specified in paragraph (c)(2) or (c)(3) of this section. Three grab samples of the waste shall be taken at equally spaced time intervals over a 1-hour period. Each 1-hour period constitutes a run, and the performance test shall consist of a minimum of 3 runs conducted over a 3-hour period. The mass flow rate of benzene entering the treatment process is calculated as follows:

$$E_b = \frac{K}{n \times 10^6} \left[\sum_{i=1}^{n} V_i C_i \right]$$

Where:

E_b = Mass flow rate of benzene entering the treatment process, kg/hr (lb/hr).

K = Density of the waste stream, kg/m^3 (lb/ft^3).

V_i = Average volume flow rate of waste entering the treatment process during each run i, m^3/hr (ft^3/hr).

C_i = Average concentration of benzene in the waste stream entering the treatment process during each run i, ppmw.

n = Number of runs.

10^6 = Conversion factor for ppmw.

(4) The mass flow rate of benzene exiting the treatment process (E_a) shall be determined by computing the product of the flow rate of the waste stream exiting the treatment process, as determined by the outlet flow meter or the inlet flow meter, and the benzene concentration of the waste stream, as determined using the sampling and analytical procedures specified in paragraph (c)(2) or (c)(3) of this section. Three grab samples of the waste shall be taken at equally spaced time intervals over a 1-hour period. Each 1-hour period constitutes a run, and the performance test shall consist of a minimum of 3 runs conducted over the same 3-hour period at which the mass flow rate of benzene entering the treatment process is determined. The mass flow rate of benzene exiting the treatment process is calculated as follows:

$$E_a = \frac{K}{n \times 10^6} \left[\sum_{i=1}^{n} V_i C_i \right]$$

Where:

E_a = Mass flow rate of benzene exiting the treatment process, kg/hr (lb/hr).

K = Density of the waste stream, kg/m^3 (lb/ft^3).

V_i = Average volume flow rate of waste exiting the treatment process during each run i, m^3/hr (ft^3/hr).

C_i = Average concentration of benzene in the waste stream exiting the treatment process during each run i, ppmw.

n = Number of runs.

10^6 = Conversion factor for ppmw.

(f) An owner or operator using performance tests to demonstrate compliance of a treatment process with § 61.348(a)(1)(iii) of this subpart shall determine the benzene destruction efficiency for the combustion unit by the following procedure:

(1) The test shall be conducted under conditions that exist when the combustion unit is operating at the highest inlet waste stream flow rate and benzene content expected to occur. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a test. The owner or operator shall record all process information necessary to document the operating conditions during the test.

(2) All testing equipment shall be prepared and installed as specified in the appropriate test methods.

(3) The mass flow rate of benzene entering the combustion unit shall be determined by computing the product of the flow rate of the waste stream entering the combustion unit, as determined by the inlet flow meter, and the benzene concentration of the waste stream, as determined using the sampling procedures in paragraph (c)(2) or (c)(3) of this section. Three grab samples of the waste shall be taken at equally spaced time intervals over a 1-hour period. Each 1-hour period constitutes a run, and the performance test shall consist of a minimum of 3 runs conducted over a 3-hour period. The mass flow rate of benzene into the combustion unit is calculated as follows:

$$E_b = \frac{K}{n \times 10^6}\left[\sum_{i=1}^{n} V_i C_i\right]$$

Where:

E_b = Mass flow rate of benzene entering the combustion unit, kg/hr (lb/hr).

K = Density of the waste stream, kg/m^3 (lb/ft^3).

V_i = Average volume flow rate of waste entering the combustion unit during each run i, m^3/hr (ft^3/hr).

C_i = Average concentration of benzene in the waste stream entering the combustion unit during each run i, ppmw.

n = Number of runs.

10^6 = Conversion factor for ppmw.

(4) The mass flow rate of benzene exiting the combustion unit exhaust stack shall be determined as follows:

(i) The time period for the test shall not be less than 3 hours during which at least 3 stack gas samples are collected and be the same time period at which the mass flow rate of benzene entering the treatment process is determined. Each sample shall be collected over a 1-hour period (e.g., in a tedlar bag) to represent a time-integrated composite sample and each 1-hour period shall correspond to the periods when the waste feed is sampled.

(ii) A run shall consist of a 1-hour period during the test. For each run:

(A) The reading from each measurement shall be recorded;

(B) The volume exhausted shall be determined using Method 2, 2A, 2C, or 2D from appendix A of 40 CFR part 60, as appropriate.

(C) The average benzene concentration in the exhaust downstream of the combustion unit shall be determined using Method 18 from appendix A of 40 CFR part 60.

(iii) The mass of benzene emitted during each run shall be calculated as follows:

$$M_i = D_b V C \left(10^{-6}\right)$$

Where:

M_i = Mass of benzene emitted during run i, kg (lb).

V = Volume of air-vapor mixture exhausted at standard conditions, m^3 (ft^3).

C = Concentration of benzene measured in the exhaust, ppmv.

D_b = Density of benzene, 3.24 kg/m^3 (0.202 lb/ft^3).

10^6 = Conversion factor for ppmv.

(iv) The benzene mass emission rate in the exhaust shall be calculated as follows:

$$E_a = \left(\sum_{i=1}^{n} M_i\right) / T$$

Where:

E_a = Mass flow rate of benzene emitted from the combustion unit, kg/hr (lb/hr).

M_i = Mass of benzene emitted from the combustion unit during run i, kg (lb).

T = Total time of all runs, hr.

n = Number of runs.

(5) The benzene destruction efficiency for the combustion unit shall be calculated as follows:

$$R = \frac{E_b - E_a}{E_b} \times 100$$

Where:

R = Benzene destruction efficiency for the combustion unit, percent.

E_b = Mass flow rate of benzene entering the combustion unit, kg/hr (lb/hr).

E_a = Mass flow rate of benzene emitted from the combustion unit, kg/hr (lb/hr).

(g) An owner or operator using performance tests to demonstrate compliance of a wastewater treatment system unit with § 61.348(b) shall measure the flow-weighted annual average benzene concentration of the wastewater stream where the waste stream enters an exempt waste management unit by collecting and analyzing a minimum of three representative samples of the waste stream using the procedures in paragraph (c)(3) of this section. The test shall be conducted under conditions that exist when the wastewater treatment system is operating at the highest inlet wastewater stream flow rate and benzene content expected to occur. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a test. The owner or operator shall record all process information as is necessary to document the operating conditions during the test.

(h) An owner or operator shall test equipment for compliance with no detectable emissions as required in §§ 61.343 through 61.347, and § 61.349 of this subpart in accordance with the following requirements:

(1) Monitoring shall comply with Method 21 from appendix A of 40 CFR part 60.

(2) The detection instrument shall meet the performance criteria of Method 21.

(3) The instrument shall be calibrated before use on each day of its use by the procedures specified in Method 21.

(4) Calibration gases shall be:

(i) Zero air (less than 10 ppm of hydrocarbon in air); and

(ii) A mixture of methane or n-hexane and air at a concentration of approximately, but less than, 10,000 ppm methane or n-hexane.

(5) The background level shall be determined as set forth in Method 21.

(6) The instrument probe shall be traversed around all potential leak interfaces as close as possible to the interface as described in Method 21.

(7) The arithmetic difference between the maximum concentration indicated by the instrument and the background level is compared to 500 ppm for determining compliance.

(i) An owner or operator using a performance test to demonstrate compliance of a control device with either the organic reduction efficiency requirement or the benzene reduction efficiency requirement specified under § 61.349(a)(2) shall use the following procedures:

(1) The test shall be conducted under conditions that exist when the waste management unit vented to the control device is operating at the highest load or capacity level expected to occur. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a test. The owner or operator shall record all process information necessary to document the operating conditions during the test.

(2) Sampling sites shall be selected using Method 1 or 1A from appendix A of 40 CFR part 60, as appropriate.

(3) The mass flow rate of either the organics or benzene entering and exiting the control device shall be determined as follows:

(i) The time period for the test shall not be less than 3 hours during which at least 3 stack gas samples are collected. Samples of the vent stream entering and exiting the control device shall be collected during the same time period. Each sample shall be collected over a 1-hour period (e.g., in a tedlar bag) to represent a time-integrated composite sample.

(ii) A run shall consist of a 1-hour period during the test. For each run:

(A) The reading from each measurement shall be recorded;

(B) The volume exhausted shall be determined using Method 2, 2A, 2C, or 2D from appendix A of 40 CFR part 60, as appropriate;

(C) The organic concentration or the benzene concentration, as appropriate, in the vent stream entering and exiting the control shall be determined using Method 18 from appendix A of 40 CFR part 60.

(iii) The mass of organics or benzene entering and exiting the control device during each run shall be calculated as follows:

$$M_{aj} = \frac{K_1 V_{aj}}{10^6} \left(\sum_{i=1}^{n} C_{ai} MW_i \right)$$

$$M_{bj} = \frac{K_1 V_{bj}}{10^6} \left(\sum_{i=1}^{n} C_{bi} MW_i \right)$$

M_{aj} = Mass of organics or benzene in the vent stream entering the control device during run j, kg (lb).

M_{bj} = Mass of organics or benzene in the vent stream exiting the control device during run j, kg (lb).

V_{aj} = Volume of vent stream entering the control device during run j, at standard conditions, m^3 (ft^3).

V_{bj} = Volume of vent stream exiting the control device during run j, at standard conditions, m^3 (ft^3).

C_{ai} = Organic concentration of compound i or the benzene concentration measured in the vent stream entering the control device as determined by Method 18, ppm by volume on a dry basis.

C_{bi} = Organic concentration of compound i or the benzene concentration measured in the vent stream exiting the control device as determined by Method 18, ppm by volume on a dry basis.

MW_i = Molecular weight of organic compound i in the vent stream, or the molecular weight of benzene, kg/kg-mol (lb/lb-mole).

n = Number of organic compounds in the vent stream; if benzene reduction efficiency is being demonstrated, then n = 1.

K_1 = Conversion factor for molar volume at standard conditions (293 K and 760 mm Hg (527 R and 14.7 psia))

= 0.0416 kg-mol/m^3 (0.00118 lb-mol/ft^3)

10^{-6} = Conversion factor for ppmv.

(iv) The mass flow rate of organics or benzene entering and exiting the control device shall be calculated as follows:

$$E_a - \left(\sum_{j=1}^{n} M_{aj} \right) / T$$

$$E_b - \left(\sum_{j=1}^{n} M_{bj} \right) / T$$

Where:

E_a = Mass flow rate of organics or benzene entering the control device, kg/hr (lb/hr).

E_b = Mass flow rate of organics or benzene exiting the control device, kg/hr (lb/hr).

M_{aj} = Mass of organics or benzene in the vent stream entering the control device during run j, kg (lb).

M_{bj} = Mass of organics or benzene in the vent stream exiting the control device during run j, kg (lb).

T = Total time of all runs, hr.

n = Number of runs.

(4) The organic reduction efficiency or the benzene reduction efficiency for the control device shall be calculated as follows:

$$R = \frac{E_a - E_b}{E_a} \times 100$$

Where:

R = Total organic reduction of efficiency or benzene reduction efficiency for the control device, percent.

E_b = Mass flow rate of organics or benzene entering the control device, kg/hr (lb/hr).

E_a = Mass flow rate of organic or benzene emitted from the control device, kg/hr (lb/hr).

(j) An owner or operator shall determine the benzene quantity for the purposes of the calculation required by § 61.342 (c)(3)(ii)(B) according to the provisions of paragraph (a) of this section, except that the procedures in paragraph (a) of this section shall also apply to wastes with a water content of 10 percent or less.

(k) An owner or operator shall determine the benzene quantity for the purposes of the calculation required by § 61.342(e)(2) by the following procedure:

(1) For each waste stream that is not controlled for air emissions in accordance with § 61.343. 61.344, 61.345, 61.346, 61.347, or 61.348(a), as applicable to the waste management unit that manages the waste, the benzene quantity shall be determined as specified in paragraph (a) of this section, except that paragraph (b)(4) of this section shall not apply, i.e., the waste quantity for process unit turnaround waste is not annualized but shall be included in the determination of benzene quantity for the year in which the waste is generated for the purposes of the calculation required by § 61.342(e)(2).

(2) For each waste stream that is controlled for air emissions in accordance with § 61.343. 61.344, 61.345, 61.346, 61.347, or 61.348(a), as applicable to the waste management unit that manages the waste, the determination of annual waste quantity and flow-weighted annual average benzene concentration shall be made at the first applicable location as described in paragraphs (k)(2)(i), (k)(2)(ii), and (k)(2)(iii) of this section and prior to any reduction of benzene concentration through volatilization of the benzene, using the methods given in (k)(2)(iv) and (k)(2)(v) of this section.

(i) Where the waste stream enters the first waste management unit not complying with §§ 61.343, 61.344, 61.345, 61.346, 61.347, and 61.348(a) that are applicable to the waste management unit,

(ii) For each waste stream that is managed or treated only in compliance with §§ 61.343 through 61.348(a) up to the point of final direct discharge from the facility, the determination of benzene quantity shall be prior to any reduction of benzene concentration through volatilization of the benzene, or

(iii) For wastes managed in units controlled for air emissions in accordance with §§ 61.343, 61.344, 61.345, 61.346, 61.347, and 61.348(a), and then transferred offsite, facilities shall use the first applicable offsite location as described in paragraphs (k)(2)(i) and (k)(2)(ii) of this section if they have documentation from the offsite facility of the benzene quantity at this location. Facilities without this documentation for offsite wastes shall use the benzene quantity determined at the point where the transferred waste leaves the facility.

(iv) Annual waste quantity shall be determined using the procedures in paragraphs (b)(5), (6), or (7) of this section, and

(v) The flow-weighted annual average benzene concentration shall be determined using the procedures in paragraphs (c)(2) or (3) of this section.

(3) The benzene quantity in a waste stream that is generated less than one time per year, including process unit turnaround waste, shall be included in the determination of benzene quantity as determined in paragraph (k)(6) of this section for the year in which the waste is generated. The benzene quantity in this waste stream shall not be annualized or averaged over the time interval between the activities that resulted in generation of the waste for purposes of determining benzene quantity as determined in paragraph (k)(6) of this section.

(4) The benzene in waste entering an enhanced biodegradation unit, as defined in § 61.348(b)(2)(ii)(B), shall not be included in the determination of benzene quantity, determined in paragraph (k)(6) of this section, if the following conditions are met:

(i) The benzene concentration for each waste stream entering the enhanced biodegradation unit is less than 10 ppmw on a flow-weighted annual average basis, and

(ii) All prior waste management units managing the waste comply with §§ 61.343, 61.344, 61.345, 61.346, 61.347 and 61.348(a).

(5) The benzene quantity for each waste stream in paragraph (k)(2) of this section shall be determined by multiplying the annual waste quantity of each waste stream times its flow-weighted annual average benzene concentration.

(6) The total benzene quantity for the purposes of the calculation required by § 61.342(e)(2) shall be determined by adding together the benzene quantities determined in paragraphs (k)(1) and (k)(5) of this section for each applicable waste stream.

(7) If the benzene quantity determined in paragraph (6) of this section exceeds 6.0 Mg/yr (6.6 ton/yr) only because of multiple counting of the benzene quantity for a waste stream, the owner or operator may use the following procedures for the purposes of the calculation required by § 61.342(e)(2):

(i) Determine which waste management units are involved in the multiple counting of benzene;

(ii) Determine the quantity of benzene that is emitted, recovered, or removed from the affected units identified in paragraph (k)(7)(i) of this section, or destroyed in the units if applicable, using either direct measurements or the best available estimation techniques developed or approved by the Administrator.

(iii) Adjust the benzene quantity to eliminate the multiple counting of benzene based on the results from paragraph (k)(7)(ii) of this section and determine the total benzene quantity for the purposes of the calculation required by § 61.342(e)(2).

(iv) Submit in the annual report required under § 61.357(a) a description of the methods used and the resulting calculations for the alternative procedure under paragraph (k)(7) of this section, the benzene quantity determination from paragraph (k)(6) of this section, and the adjusted benzene quantity determination from paragraph (k)(7)(iii) of this section.

[55 FR 8346, Mar. 7, 1990; 55 FR 12444, Apr. 3, 1990, as amended at 55 FR 37231, Sept. 10, 1990; 58 FR 3099, Jan. 7, 1993; 65 FR 62160, Oct. 17, 2000]

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Submerged filling means, for the purposes of this subpart, the filling of a gasoline storage tank through a submerged fill pipe whose discharge is no more than the applicable distance specified in § 63.11117(b) from the bottom of the tank. Bottom filling of gasoline storage tanks is included in this definition.

Vapor balance system means a combination of pipes and hoses that create a closed system between the vapor spaces of an unloading gasoline cargo tank and a receiving storage tank such that vapors displaced from the storage tank are transferred to the gasoline cargo tank being unloaded.

Vapor-tight means equipment that allows no loss of vapors. Compliance with vapor-tight requirements can be determined by checking to ensure that the concentration at a potential leak source is not equal to or greater than 100 percent of the Lower Explosive Limit when measured with a combustible gas detector, calibrated with propane, at a distance of 1 inch from the source.

Vapor-tight gasoline cargo tank means a gasoline cargo tank which has demonstrated within the 12 preceding months that it meets the annual certification test requirements in § 63.11092(f) of this part.

[73 FR 1945, Jan. 10, 2008, as amended at 76 FR 4183, Jan. 24, 2011]

Table 1 to Subpart CCCCCC of Part 63—Applicability Criteria and Management Practices for Gasoline Dispensing Facilities With Monthly Throughput of 100,000 Gallons of Gasoline or More[1]

If you own or operate	Then you must
1. A new, reconstructed, or existing GDF subject to § 63.11118	Install and operate a vapor balance system on your gasoline storage tanks that meets the design criteria in paragraphs (a) through (h).
	(a) All vapor connections and lines on the storage tank shall be equipped with closures that seal upon disconnect.
	(b) The vapor line from the gasoline storage tank to the gasoline cargo tank shall be vapor-tight, as defined in § 63.11132.
	(c) The vapor balance system shall be designed such that the pressure in the tank truck does not exceed 18 inches water pressure or 5.9 inches water vacuum during product transfer.
	(d) The vapor recovery and product adaptors, and the method of connection with the delivery elbow, shall be designed so as to prevent the over-tightening or loosening of fittings during normal delivery operations.
	(e) If a gauge well separate from the fill tube is used, it shall be provided with a submerged drop tube that extends the same distance from the bottom of the storage tank as specified in § 63.11117(b).
	(f) Liquid fill connections for all systems shall be equipped with vapor-tight caps.
	(g) Pressure/vacuum (PV) vent valves shall be installed on the storage tank vent pipes. The pressure specifications for PV vent valves shall be: a positive pressure setting of 2.5 to 6.0 inches of water and a negative pressure setting of 6.0 to 10.0 inches of water. The total leak rate of all PV vent valves at an affected facility, including connections, shall not exceed 0.17 cubic foot per hour at a pressure of 2.0 inches of water and 0.63 cubic foot per hour at a vacuum of 4 inches of water.
	(h) The vapor balance system shall be capable of meeting the static pressure

If you own or operate	Then you must
	performance requirement of the following equation:
	$Pf = 2e^{-500.887/v}$
	Where:
	Pf = Minimum allowable final pressure, inches of water.
	v = Total ullage affected by the test, gallons.
	e = Dimensionless constant equal to approximately 2.718.
	2 = The initial pressure, inches water.
2. A new or reconstructed GDF, or any storage tank(s) constructed after November 9, 2006, at an existing affected facility subject to § 63.11118	Equip your gasoline storage tanks with a dual-point vapor balance system, as defined in § 63.11132, and comply with the requirements of item 1 in this Table.

[1] The management practices specified in this Table are not applicable if you are complying with the requirements in § 63.11118(b)(2), except that if you are complying with the requirements in § 63.11118(b)(2)(i)(B), you must operate using management practices at least as stringent as those listed in this Table.

[73 FR 1945, Jan. 10, 2008, as amended at 73 FR 35944, June 25, 2008; 76 FR 4184, Jan. 24, 2011]

Table 2 to Subpart CCCCCC of Part 63—Applicability Criteria and Management Practices for Gasoline Cargo Tanks Unloading at Gasoline Dispensing Facilities With Monthly Throughput of 100,000 Gallons of Gasoline or More

If you own or operate	Then you must
A gasoline cargo tank	Not unload gasoline into a storage tank at a GDF subject to the control requirements in this subpart unless the following conditions are met:
	(i) All hoses in the vapor balance system are properly connected,
	(ii) The adapters or couplers that attach to the vapor line on the storage tank have closures that seal upon disconnect,
	(iii) All vapor return hoses, couplers, and adapters used in the gasoline delivery are vapor-tight,
	(iv) All tank truck vapor return equipment is compatible in size and forms a vapor-tight connection with the vapor balance equipment on the GDF storage tank, and
	(v) All hatches on the tank truck are closed and securely fastened.
	(vi) The filling of storage tanks at GDF shall be limited to unloading from vapor-tight gasoline cargo tanks. Documentation that the cargo tank has met the specifications of EPA Method 27 shall be carried with the cargo tank, as specified in § 63.11125(c).

[73 FR 1945, Jan. 10, 2008, as amended at 76 FR 4184, Jan. 24, 2011]

Table 3 to Subpart CCCCCC of Part 63—Applicability of General Provisions

Citation	Subject	Brief description	Applies to subpart CCCCCC
§ 63.1	Applicability	Initial applicability determination; applicability after standard established; permit requirements; extensions, notifications	Yes, specific requirements given in § 63.11111.
§ 63.1(c)(2)	Title V Permit	Requirements for obtaining a title V permit from the applicable permitting authority	Yes, § 63.11111(f) of subpart CCCCCC exempts identified area sources from the obligation to obtain title V operating permits.
§ 63.2	Definitions	Definitions for part 63 standards	Yes, additional

Citation	Subject	Brief description	Applies to subpart CCCCCC
			definitions in § 63.11132.
§ 63.3	Units and Abbreviations	Units and abbreviations for part 63 standards	Yes.
§ 63.4	Prohibited Activities and Circumvention	Prohibited activities; Circumvention, severability	Yes.
§ 63.5	Construction/ Reconstruction	Applicability; applications; approvals	Yes, except that these notifications are not required for facilities subject to § 63.11116
§ 63.6(a)	Compliance with Standards/Operation & Maintenance—Applicability	General Provisions apply unless compliance extension; General Provisions apply to area sources that become major	Yes.
§ 63.6(b)(1)–(4)	Compliance Dates for New and Reconstructed Sources	Standards apply at effective date; 3 years after effective date; upon startup; 10 years after construction or reconstruction commences for CAA section 112(f)	Yes.
§ 63.6(b)(5)	Notification	Must notify if commenced construction or reconstruction after proposal	Yes.
§ 63.6(b)(6)	[Reserved]		
§ 63.6(b)(7)	Compliance Dates for New and Reconstructed Area Sources That Become Major	Area sources that become major must comply with major source standards immediately upon becoming major, regardless of whether required to comply when they were an area source	No.
§ 63.6(c)(1)–(2)	Compliance Dates for Existing Sources	Comply according to date in this subpart, which must be no later than 3 years after effective date; for CAA section 112(f) standards, comply within 90 days of effective date unless compliance extension	No, § 63.11113 specifies the compliance dates.
§ 63.6(c)(3)–(4)	[Reserved]		
§ 63.6(c)(5)	Compliance Dates for Existing Area Sources That Become Major	Area sources That become major must comply with major source standards by date indicated in this subpart or by equivalent time period (e.g., 3 years)	No.
§ 63.6(d)	[Reserved]		

Citation	Subject	Brief description	Applies to subpart CCCCCC
63.6(e)(1)(i)	General duty to minimize emissions	Operate to minimize emissions at all times; information Administrator will use to determine if operation and maintenance requirements were met.	No. *See* § 63.11115 for general duty requirement.
63.6(e)(1)(ii)	Requirement to correct malfunctions ASAP	Owner or operator must correct malfunctions as soon as possible.	No.
§ 63.6(e)(2)	[Reserved]		
§ 63.6(e)(3)	Startup, Shutdown, and Malfunction (SSM) Plan	Requirement for SSM plan; content of SSM plan; actions during SSM	No.
§ 63.6(f)(1)	Compliance Except During SSM	You must comply with emission standards at all times except during SSM	No.
§ 63.6(f)(2)–(3)	Methods for Determining Compliance	Compliance based on performance test, operation and maintenance plans, records, inspection	Yes.
§ 63.6(g)(1)–(3)	Alternative Standard	Procedures for getting an alternative standard	Yes.
§ 63.6(h)(1)	Compliance with Opacity/ Visible Emission (VE) Standards	You must comply with opacity/VE standards at all times except during SSM	No.
§ 63.6(h)(2)(i)	Determining Compliance with Opacity/VE Standards	If standard does not State test method, use EPA Method 9 for opacity in appendix A of part 60 of this chapter and EPA Method 22 for VE in appendix A of part 60 of this chapter	No.
§ 63.6(h)(2)(ii)	[Reserved]		
§ 63.6(h)(2)(iii)	Using Previous Tests To Demonstrate Compliance With Opacity/VE Standards	Criteria for when previous opacity/VE testing can be used to show compliance with this subpart	No.
§ 63.6(h)(3)	[Reserved]		
§ 63.6(h)(4)	Notification of Opacity/VE Observation Date	Must notify Administrator of anticipated date of observation	No.
§ 63.6(h)(5)(i), (iii)–(v)	Conducting Opacity/VE Observations	Dates and schedule for conducting opacity/VE observations	No.
§ 63.6(h)(5)(ii)	Opacity Test Duration and Averaging Times	Must have at least 3 hours of observation with 30 6-minute averages	No.
§ 63.6(h)(6)	Records of Conditions During Opacity/VE Observations	Must keep records available and allow Administrator to inspect	No.
§ 63.6(h)(7)(i)	Report Continuous Opacity Monitoring System (COMS) Monitoring Data	Must submit COMS data with other performance test data	No.

Citation	Subject	Brief description	Applies to subpart CCCCCC
	From Performance Test		
§ 63.6(h)(7)(ii)	Using COMS Instead of EPA Method 9	Can submit COMS data instead of EPA Method 9 results even if rule requires EPA Method 9 in appendix A of part 60 of this chapter, but must notify Administrator before performance test	No.
§ 63.6(h)(7)(iii)	Averaging Time for COMS During Performance Test	To determine compliance, must reduce COMS data to 6-minute averages	No.
§ 63.6(h)(7)(iv)	COMS Requirements	Owner/operator must demonstrate that COMS performance evaluations are conducted according to § 63.8(e); COMS are properly maintained and operated according to § 63.8(c) and data quality as § 63.8(d)	No.
§ 63.6(h)(7)(v)	Determining Compliance with Opacity/VE Standards	COMS is probable but not conclusive evidence of compliance with opacity standard, even if EPA Method 9 observation shows otherwise. Requirements for COMS to be probable evidence-proper maintenance, meeting Performance Specification 1 in appendix B of part 60 of this chapter, and data have not been altered	No.
§ 63.6(h)(8)	Determining Compliance with Opacity/VE Standards	Administrator will use all COMS, EPA Method 9 (in appendix A of part 60 of this chapter), and EPA Method 22 (in appendix A of part 60 of this chapter) results, as well as information about operation and maintenance to determine compliance	No.
§ 63.6(h)(9)	Adjusted Opacity Standard	Procedures for Administrator to adjust an opacity standard	No.
§ 63.6(i)(1)–(14)	Compliance Extension	Procedures and criteria for Administrator to grant compliance extension	Yes.
§ 63.6(j)	Presidential Compliance Exemption	President may exempt any source from requirement to comply with this subpart	Yes.
§ 63.7(a)(2)	Performance Test Dates	Dates for conducting initial performance testing; must conduct 180 days after compliance date	Yes.
§ 63.7(a)(3)	CAA Section 114 Authority	Administrator may require a performance test under CAA section 114 at any time	Yes.

Citation	Subject	Brief description	Applies to subpart CCCCCC
§ 63.7(b)(1)	Notification of Performance Test	Must notify Administrator 60 days before the test	Yes.
§ 63.7(b)(2)	Notification of Re-scheduling	If have to reschedule performance test, must notify Administrator of rescheduled date as soon as practicable and without delay	Yes.
§ 63.7(c)	Quality Assurance (QA)/Test Plan	Requirement to submit site-specific test plan 60 days before the test or on date Administrator agrees with; test plan approval procedures; performance audit requirements; internal and external QA procedures for testing	Yes.
§ 63.7(d)	Testing Facilities	Requirements for testing facilities	Yes.
63.7(e)(1)	Conditions for Conducting Performance Tests	Performance test must be conducted under representative conditions	No, § 63.11120(c) specifies conditions for conducting performance tests.
§ 63.7(e)(2)	Conditions for Conducting Performance Tests	Must conduct according to this subpart and EPA test methods unless Administrator approves alternative	Yes.
§ 63.7(e)(3)	Test Run Duration	Must have three test runs of at least 1 hour each; compliance is based on arithmetic mean of three runs; conditions when data from an additional test run can be used	Yes.
§ 63.7(f)	Alternative Test Method	Procedures by which Administrator can grant approval to use an intermediate or major change, or alternative to a test method	Yes.
§ 63.7(g)	Performance Test Data Analysis	Must include raw data in performance test report; must submit performance test data 60 days after end of test with the Notification of Compliance Status; keep data for 5 years	Yes.
§ 63.7(h)	Waiver of Tests	Procedures for Administrator to waive performance test	Yes.
§ 63.8(a)(1)	Applicability of Monitoring Requirements	Subject to all monitoring requirements in standard	Yes.
§ 63.8(a)(2)	Performance Specifications	Performance Specifications in appendix B of 40 CFR part 60 apply	Yes.

Citation	Subject	Brief description	Applies to subpart CCCCCC
§ 63.8(a)(3)	[Reserved]		
§ 63.8(a)(4)	Monitoring of Flares	Monitoring requirements for flares in § 63.11 apply	Yes.
§ 63.8(b)(1)	Monitoring	Must conduct monitoring according to standard unless Administrator approves alternative	Yes.
§ 63.8(b)(2)–(3)	Multiple Effluents and Multiple Monitoring Systems	Specific requirements for installing monitoring systems; must install on each affected source or after combined with another affected source before it is released to the atmosphere provided the monitoring is sufficient to demonstrate compliance with the standard; if more than one monitoring system on an emission point, must report all monitoring system results, unless one monitoring system is a backup	No.
§ 63.8(c)(1)	Monitoring System Operation and Maintenance	Maintain monitoring system in a manner consistent with good air pollution control practices	No.
§ 63.8(c)(1)(i)–(iii)	Operation and Maintenance of Continuous Monitoring Systems (CMS)	Must maintain and operate each CMS as specified in § 63.6(e)(1); must keep parts for routine repairs readily available; must develop a written SSM plan for CMS, as specified in § 63.6(e)(3)	No.
§ 63.8(c)(2)–(8)	CMS Requirements	Must install to get representative emission or parameter measurements; must verify operational status before or at performance test	No.
§ 63.8(d)	CMS Quality Control	Requirements for CMS quality control, including calibration, etc.; must keep quality control plan on record for 5 years; keep old versions for 5 years after revisions	No.
§ 63.8(e)	CMS Performance Evaluation	Notification, performance evaluation test plan, reports	No.
§ 63.8(f)(1)–(5)	Alternative Monitoring Method	Procedures for Administrator to approve alternative monitoring	No.
§ 63.8(f)(6)	Alternative to Relative Accuracy Test	Procedures for Administrator to approve alternative relative accuracy tests for continuous emissions monitoring system (CEMS)	No.

Citation	Subject	Brief description	Applies to subpart CCCCCC
§ 63.8(g)	Data Reduction	COMS 6-minute averages calculated over at least 36 evenly spaced data points; CEMS 1 hour averages computed over at least 4 equally spaced data points; data that cannot be used in average	No.
§ 63.9(a)	Notification Requirements	Applicability and State delegation	Yes.
§ 63.9(b)(1)–(2), (4)–(5)	Initial Notifications	Submit notification within 120 days after effective date, or no later than 120 days after the source becomes subject to this subpart, whichever is later; notification of intent to construct/reconstruct, notification of commencement of construction/ reconstruction, notification of startup; contents of each	Yes.
§ 63.9(c)	Request for Compliance Extension	Can request if cannot comply by date or if installed best available control technology or lowest achievable emission rate	Yes.
§ 63.9(d)	Notification of Special Compliance Requirements for New Sources	For sources that commence construction between proposal and promulgation and want to comply 3 years after effective date	Yes.
§ 63.9(e)	Notification of Performance Test	Notify Administrator 60 days prior	Yes.
§ 63.9(f)	Notification of VE/Opacity Test	Notify Administrator 30 days prior	No.
§ 63.9(g)	Additional Notifications when Using CMS	Notification of performance evaluation; notification about use of COMS data; notification that exceeded criterion for relative accuracy alternative	Yes, however, there are no opacity standards.
§ 63.9(h)(1)–(6)	Notification of Compliance Status	Contents due 60 days after end of performance test or other compliance demonstration, except for opacity/VE, which are due 30 days after; when to submit to Federal vs. State authority	Yes, however, there are no opacity standards.
§ 63.9(i)	Adjustment of Submittal Deadlines	Procedures for Administrator to approve change when notifications must be submitted	Yes.
§ 63.9(j)	Change in Previous Information	Must submit within 15 days after the change	Yes.
§ 63.9(k)	Notifications	Electronic reporting procedures	Yes, only as specified in §

Citation	Subject	Brief description	Applies to subpart CCCCCC
			63.9(j).
§ 63.10(a)	Recordkeeping/Reporting	Applies to all, unless compliance extension; when to submit to Federal vs. State authority; procedures for owners of more than one source	Yes.
§ 63.10(b)(1)	Recordkeeping/Reporting	General requirements; keep all records readily available; keep for 5 years	Yes.
§ 63.10(b)(2)(i)	Records related to SSM	Recordkeeping of occurrence and duration of startups and shutdowns	No.
§ 63.10(b)(2)(ii)	Records related to SSM	Recordkeeping of malfunctions	No. *See* § 63.11125(d) for recordkeeping of (1) occurrence and duration and (2) actions taken during malfunction.
§ 63.10(b)(2)(iii)	Maintenance records	Recordkeeping of maintenance on air pollution control and monitoring equipment	Yes.
§ 63.10(b)(2)(iv)	Records Related to SSM	Actions taken to minimize emissions during SSM	No.
§ 63.10(b)(2)(v)	Records Related to SSM	Actions taken to minimize emissions during SSM	No.
§ 63.10(b)(2)(vi)–(xi)	CMS Records	Malfunctions, inoperative, out-of-control periods	No.
§ 63.10(b)(2)(xii)	Records	Records when under waiver	Yes.
§ 63.10(b)(2)(xiii)	Records	Records when using alternative to relative accuracy test	Yes.
§ 63.10(b)(2)(xiv)	Records	All documentation supporting Initial Notification and Notification of Compliance Status	Yes.
§ 63.10(b)(3)	Records	Applicability determinations	Yes.
§ 63.10(c)	Records	Additional records for CMS	No.
§ 63.10(d)(1)	General Reporting Requirements	Requirement to report	Yes.
§ 63.10(d)(2)	Report of Performance Test Results	When to submit to Federal or State authority	Yes.
§ 63.10(d)(3)	Reporting Opacity or VE Observations	What to report and when	No.

Citation	Subject	Brief description	Applies to subpart CCCCCC
§ 63.10(d)(4)	Progress Reports	Must submit progress reports on schedule if under compliance extension	Yes.
§ 63.10(d)(5)	SSM Reports	Contents and submission	No. *See* § 63.11126(b) for malfunction reporting requirements.
§ 63.10(e)(1)–(2)	Additional CMS Reports	Must report results for each CEMS on a unit; written copy of CMS performance evaluation; two-three copies of COMS performance evaluation	No.
§ 63.10(e)(3)(i)–(iii)	Reports	Schedule for reporting excess emissions	No.
§ 63.10(e)(3)(iv)–(v)	Excess Emissions Reports	Requirement to revert to quarterly submission if there is an excess emissions and parameter monitor exceedances (now defined as deviations); provision to request semiannual reporting after compliance for 1 year; submit report by 30th day following end of quarter or calendar half; if there has not been an exceedance or excess emissions (now defined as deviations), report contents in a statement that there have been no deviations; must submit report containing all of the information in §§ 63.8(c)(7)–(8) and 63.10(c)(5)–(13)	No.
§ 63.10(e)(3)(iv)–(v)	Excess Emissions Reports	Requirement to revert to quarterly submission if there is an excess emissions and parameter monitor exceedances (now defined as deviations); provision to request semiannual reporting after compliance for 1 year; submit report by 30th day following end of quarter or calendar half; if there has not been an exceedance or excess emissions (now defined as deviations), report contents in a statement that there have been no deviations; must submit report containing all of the information in §§	No, § 63.11130(K) specifies excess emission events for this subpart.

Citation	Subject	Brief description	Applies to subpart CCCCCC
		63.8(c)(7)–(8) and 63.10(c)(5)–(13)	
§ 63.10(e)(3)(vi)–(viii)	Excess Emissions Report and Summary Report	Requirements for reporting excess emissions for CMS; requires all of the information in §§ 63.10(c)(5)–(13) and 63.8(c)(7)–(8)	No.
§ 63.10(e)(4)	Reporting COMS Data	Must submit COMS data with performance test data	No.
§ 63.10(f)	Waiver for Recordkeeping/ Reporting	Procedures for Administrator to waive	Yes.
§ 63.11(b)	Flares	Requirements for flares	No.
§ 63.12	Delegation	State authority to enforce standards	Yes.
§ 63.13	Addresses	Addresses where reports, notifications, and requests are sent	Yes.
§ 63.14	Incorporations by Reference	Test methods incorporated by reference	Yes.
§ 63.15	Availability of Information	Public and confidential information	Yes.

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